STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 97-580

March 19, 1999

PUBLIC UTILITIES COMMISSION
Investigation of Central Maine Power Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design

ORDER

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WELCH, Chairman; NUGENT, and DIAMOND Commissioners

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SUMMARY

We decide the principles by which we will set CMP's transmission and distribution (T&D) rates, effective March 1, 2000. We do not calculate rates at this time because any calculation would rely excessively on estimates. Information to convert most of the estimates into "hard" numbers will become available during 1999. We will have a "Phase II" proceeding to process the newly available information. Our T&D revenue requirement will include a cost of equity of 10.5%, and a capital structure that includes 47% equity. Our stranded cost decisions assume that the sale to FPL will close this year. We adopt a "no losers" policy for any rate design changes, meaning that rate design changes will not result in rate increases for any customers. This "no loser" policy, together with other considerations, leads us to reject the CMP's standby rate proposal.

INTRODUCTION

In this case, the Commission implements the legislative directive in the Restructuring Act (35-A M.R.S.A. §§ 3201-3217) to prepare CMP's rates for the fundamental restructuring of the electric industry on March 1, 2000. On that date, electric generation retail service becomes subject to competition rather than rate regulation. The delivery of electricity will remain regulated as a utility service.

Although restructuring requires a fundamental change in the electric industry, in many ways it is a logical extension of the regulatory policies we began implementing in 1992. In that year we permitted Central Maine Power Company to adjust its rates through special contracts, to maintain load in the face of competition from lower rates in another New England state and where customers had the ability to economically self-generate. *See, Investigation of Airco Industrial Gases Request for Interruptible Load Retention Service Rate with Central Maine Power Company,* Docket No. 92-331, Order, (Mar. 25, 1994)*; Joint Request of Central Maine Power Company and Ski Maine Association for Approval of Special Rate Tariff,* Docket No. 94-134, Order, (June 16, 1994); and *Request to Central Maine Power for Approval of Special Rate Tariff for Sawmills,* Docket No. 94-276, Order, (Sept. 26, 1994) . Maintaining load as a means of maintaining contribution to system costs became an important consideration in Maine regulation.

In Docket No. 92-345, we found that CMP's costs were too high and that the Company was operating inefficiently. In addition to adjusting rates to remove the inefficiency, we started the process, after explicit legislative authorization, to implement an incentive ratemaking mechanism, which for CMP was called the Alternative Rate Plan (ARP). We can now conclude that the ARP worked. Under the ARP, rates were adjusted not in accordance with changes in costs, but in accordance with an index tied to inflation and expected productivity. Greater risks and rewards were placed on the Company and its shareholders. Under the limitations of the ARP, ratepayers were no longer exposed to the risk of significant cost increases. Now with the deregulation of generation, the most price-volatile sector of the electric utility industry will be subject to competition. With that significant change, ratepayers will no longer bear any of the business risks associated with CMP's generation assets, as the price of electric generation will be subject to market forces.

The Restructuring Act requires each electric utility to divest generation-related assets and businesses. The Commission must conduct adjudicatory proceedings to determine for each utility the generation costs stranded by restructuring. In the same proceeding, the Commission must determine the revenue requirement for the remaining transmission and distribution utility and the stranded cost charges that will be collected through the T&D rates. 35-A M.R.S.A. § 3208(8). These adjudicatory proceedings must be concluded by July 1, 1999*. Id.*

The Commission must also design rates to recover the revenue requirement for T&D costs, stranded costs, and any other costs required by the Act to be recovered through T&D rates. The Act also requires the Commission to design rates for backup or standby service. These rate design adjudicatory proceedings must be complete by October 1, 1999. *Id*. at §3209.

With the increased workload caused by restructuring, it is important for the Commission to use its resources efficiently. Accordingly, the Commission conducted the adjudicatory proceedings, including this one, with an advisory staff only and without assigning staff advocates, a procedure known as the "hot bench." By the hot bench, the Commission could assign one team rather than two teams to each proceeding, virtually cutting in half the Commission resources necessary for each proceeding. The more-efficient one-team approach required advisors, not advocates, so that Commission staff could advise and assist each Commissioner throughout the case.

Since the hot bench approach had never been used in a major proceeding, we modified traditional Commission procedure to accommodate the concerns of the parties. Advisors participated in technical conferences that replaced depositions. A Bench Analysis, essentially a preliminary examiner's report, was issued in middle of the proceeding. Parties had the opportunity to question advisors on the Bench Analysis, and to file testimony to rebut it. In addition, parties could again question advisors at the hearings.

We believe that the hot bench procedure accomplished all of our goals. We processed a case that was the equivalent of three major proceedings without staff advocates. While using fewer Commission resources, we did not sacrifice quality in the evidence offered or the analysis performed by the staff and the parties.[1] The

[1]The resources "unexpended" in this case were effectively used to write the more than a score of legislatively mandated rules necessary to implement restructuring. We believe the procedure provided the parties with a fair opportunity to adjust to the

Commission initiated this proceeding to satisfy the Restructuring Act's statutory requirements, specifically to determine CMP's T&D costs and stranded costs, and to design rates to recover those costs. CMP is the first electric utility for which the Commission has conducted the necessary adjudicatory proceeding. With more electric utilities to follow, we necessarily must finish the first case about a year before the date of retail competition. Therefore, many of the decisions in this phase of the case establish the ratemaking principles before actual rates can be calculated.[2]

In deciding the principles we will use to establish the T&D revenue requirement, we need to balance two conflicting goals: to assure the financial strength of the T&D utility and to mitigate stranded costs. In designing the rates to collect that revenue requirement, we will be governed by a "no losers" principle. "No losers" means we intend not to implement rate design changes that will increase rates for customers on March 1, 2000. Restructuring was not enacted to increase the rates for any customers. The existence of available value for the asset sale permits us to adhere to the "no losers" principle while performing modest rate design changes.

Actual rates must await updated information. We will conduct a Phase II proceeding to process the additional information necessary to calculate CMP's T&D rates. The matters to be addressed in Phase II are discussed in detail throughout this Order.

We expect the determination of CMP's T&D and stranded cost revenue requirement, and the design of rates to recover that revenue requirement in "Phase I" and the "Phase II update", to carry CMP and its ratepayers through the first two to three years of restructuring. By the end of that period, the Commission plans to complete the next T&D rate case, in which we can examine T&D costs, devise a new rate plan for the T&D utility if appropriate and take a new look at the proper rate design for the T&D utility.

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new means of staff input. While we believe the procedure in the case was fair and proper, we welcome an open dialogue with the parties for suggestions on improving the "hot bench" approach.

[2]As the case of first impression, we expect the principles established in this Order to guide us and speed the processing of the other utilities' proceedings.

Part 1 - REVENUE REQUIREMENT

I. OVERVIEW

To establish the rates that CMP will charge as of March 1, 2000, we must first determine the Company's revenue requirement and then allocate that amount to the various rate classes from which the structure of the actual rates will be determined. This procedure is essentially the same one we have followed in all previous revenue requirement cases.

The current case, however, differs significantly from virtually every other rate case we have decided in the past. First, the utility for which we are setting rates will exist in a form different from the CMP of today. CMP is currently an integrated utility supplying electric energy to its customers. As of March 1, 2000, it will only deliver power sold by other, unregulated entities. Therefore, we must project the costs and revenues of the new "wires" company during its initial year as a power deliverer. While in past rate cases we have generally undertaken an attrition analysis for the rate effective year, the instant case requires an even greater use of projections than in the past. Along with the projected levels of revenue, expense and investment, we must determine an allowed rate of return for the new entity. We must consider the level of risk that will be present so that we can establish an appropriate return on equity for the T&D operation, as well as an appropriate capital structure. Both of these decisions depend heavily on our assessment of the level of business and financial risk that will exist for the new T&D entity. Because there is virtually no direct, empirical evidence available for this analysis, we must, to a great extent, rely on evidence drawn from analogous circumstances and on our judgment.

Related to the change in physical operations is CMP's decision to reorganize into a holding company structure. While not required by the restructuring statute, CMP changed its corporate form to make it easier for CMP Group, Inc. (the name of the holding company) to enter into business ventures other than that of an electric wires company. This reorganization further complicates to the revenue requirement calculation, because the holding company performs many administrative and general functions for each of the operational units. From a corporate efficiency point of view, this may be the proper approach, but for ratemaking purposes, it requires that we find a method to ensure that the costs incurred by the holding company are properly allocated to the various organizational entities, including the T&D company, CMP. While we do not assume, or mean to imply, that the Company has any improper intentions, we cannot ignore the natural incentive of the holding company to have as much of its costs as possible recovered through the regulated rates of the T&D Company for its monopoly services.

Another problem in setting revenue requirements for the T&D utility is the potential for the test year data to be stale. The period from the end of the test year (1996) until the start of the rate year (March 1, 2000) is three years and two months, an extraordinarily long time when considered in relation to most prior rate case proceedings. This rather substantial interval is at least partially due to the requirement in the Restructuring Act that the rate case proceedings for the T&D utilities be completed by July 1, 1999. We will have the opportunity to update some of the amounts before rates are implemented, but we must to exercise even more care than usual in evaluating the revenue requirement proposals.

Finally, when setting the total amount of revenue requirements for CMP, we must consider the amount of the Company's stranded costs, many of which are related to regulatory assets that have been created in prior rate cases. In addition, much of the stranded cost amount stems from the above-market QF contracts that CMP will retain and whose output CMP will attempt to market. The excess value that CMP was able to obtain by selling its generating assets, as required by the restructuring statute, is available to offset these stranded costs. The excess value allows us to eliminate a significant portion of the regulatory assets that currently remain on CMP's books, as well as to provide a "fund" to use in offsetting the ongoing amount of stranded costs. We are in the fortunate situation of having to decide the disposition of the excess value, including the amount due ratepayers and the time period over which ratepayers will receive this benefit.

We address each of the above-described areas in detail in the following sections. Where we do not reach a final decision, we will describe the principles and parameters according to which a decision will be made in Phase II.

II. COST SEPARATIONS

A. Summary of Issue

Unlike any recent rate case, the Commission in this case must set a revenue requirement for an entity, a T&D utility, that did not exist in the test year and will not exist until the beginning of the rate effective year. As part of this process the Commission must project a reasonable level of expense for the T&D utility in the rate effective period and also project what expenses can reasonably be avoided as a result of the Company's divestiture of its generation assets.

The Company in this case is using a 1996 test year, which is based on CMP's activities as an integrated electric utility. Thus, the financial results from this test year must be separated so that we can derive a T&D only revenue requirement for the rate effective year.

B. Positions Before the Commission

CMP's cost separation study was submitted by Company Comptroller Michael Caron, and Rate Analyst Carol Dufour, (hereinafter, "Caron/Dufour"). Using test year accounting data, Caron/Dufour separated costs into five separate business groups: the holding company, the T&D utility, the wholesale and retail marketing business (referred to as the "energy" business), the operations support division, and the other subsidiaries. The first step in the Caron/Dufour separations process was to remove directly identifiable and assignable generation costs, stranded costs and rate proceeding "eliminations."[3] After removing these costs, the remaining financial data were segregated into the four remaining cost categories: T&D, Wholesale and Retail, Operating Support Division and the Holding Company.

After this separation, OSD and Holding Company costs were approportioned between T&D and the wholesale and retail (W&R) business units. This was accomplished when possible on a direct basis and for much of the rest on an indirect cost allocation basis. A pool of residual costs remained after these direct and indirect allocations were completed, and these were assigned to the T&D and wholesale units based on a global allocator. The Company's global allocator was based on the revenues, expenses and assets of each of the operating units. Each of these factors was derived by dividing the amount for the operating unit by the total amount for the factor. The global allocator was developed by giving each factor an equal weight and summing the products. Based on these assignments, Holding Company and OSD costs were allocated between T&D and Wholesale/Retail as follows:

	Holding Company Costs ($000)	OSD Costs ($000)
Transmission & Distribution	$1,451	$52,062
Wholesale/Retail	177	3,999
TOTAL	**$1,628**	**$56,061**

James Dittmer, testifying on behalf of the OPA, did not dispute the general methodology employed by CMP. Mr. Dittmer believed, however, that the Company generally used what he termed "conservative assumptions" regarding the number of support positions that can be eliminated after divestiture. Mr. Dittmer noted that the Company assumed that costs will continue to be incurred at the test year levels, notwithstanding the significant downsizing anticipated with divestiture. In other words, "CMP's study tends to consider most administrative and general costs to be relatively fixed irrespective of whether the production function is divested." Mr. Dittmer also asserted that of the total test year A&G expense of $47,617,000, CMP directly assigned $2,099,000 to the production function. Of the remaining $45,523,000 of A&G costs, CMP estimated it could only eliminate an additional $2,370,000, or approximately 5%, through the elimination of 18 support positions.

[3]Rate proceeding eliminations are amounts that are not assigned to any business unit in the test year disaggregation. Operating Revenues and Income Taxes are examples of those eliminations.

Mr. Dittmer recommended four discrete adjustments, as well as one general adjustment, to the Company's study. Specifically, Mr. Dittmer recommended that "general" and "legal retainer" costs be reduced based on the ratio of generation-specific outside legal services costs to the total of test-year outside legal services costs and that two-thirds ($461,000) of the Governmental Affairs costs recorded above the line in the test year be removed based on the employees' job descriptions. CMP agreed in principle with the proposed change, and as described in subsection II(C)(2), the amount of this adjustment is accepted at an uncontested level of $369,062.

In addition, Mr. Dittmer recommended removing $1,269,771 of the $2,252,300 of test year advertising expense allocated to the T&D company. He also advocated reducing Research and Records costs by $500,000 from the 1996 test year level of $954,000. In support of this adjustment, he pointed to the $400,000 - $500,000 decrease in this expense between 1995 and 1996 and once again between 1996 and 1997. Mr. Dittmer further noted that the Research and Records expenses were not budgeted to go up in 1998.

Finally, Mr. Dittmer recommended that prior to the onset of restructuring the Commission revisit the cost separations issue and look at specific items, including:

- Number of Directors, Directors' total compensation and liability insurance required for Directors of a monopolistic T&D company;
- Professional organization memberships for a T&D-only utility company;
- Computer hardware and software support;
- Employee recruiting and relocation costs for a downsized T&D company;
- Bank service fees paid to secure lines of credit for a less-heavily-capitalized utility company; and
- Reduced rates and revenue requirements costs after divestiture is complete and many one-time, non-recurring issues are resolved.

In lieu of this review, Mr. Dittmer recommended that A&G costs be reduced by two percent. Mr. Dittmer stated that "admittedly, the application of the two percent reduction is quite subjective but nonetheless, believed to be a conservative estimate of additional savings to be realized following divestiture."

Dr. Silkman, on behalf of the IECG, provided some general criticisms of the Company's study. First, Dr. Silkman argued that CMP's top-down approach was inappropriate, because costs that cannot be allocated to future business units are presumptively allocated to the T&D utility. Dr. Silkman found troubling CMP's identification of only $4.4 million of A&G costs as being generation-related out of a total of $45.1 million. This caused Dr. Silkman to pose the question:

> If CMP were an efficiently structured and operated T&D only utility would it only incur an additional $4.5 million, or 10% increase, in A&G costs if it be transformed into a vertically integrated utility with in excess of 1,000 mW of generating capacity and scores of purchased power contracts?

Second, Dr. Silkman testified that the separations study over-allocates holding company costs to the T&D operation, because the study uses global allocations that are based on the size and scope of the business in the test year, and CMP has subsequently reorganized into a holding company structure. Dr. Silkman's third concern was that the test year level of sales marketing expenses appeared artificially low and that no sales, marketing or advertising expense were allocated to generation. Finally, Dr. Silkman expressed concern that the test year levels of expense were incurred while the Company was under an ARP and not subject to regulatory scrutiny.

The Bench Analysis expressed concerns similar to those of Dr. Silkman and Mr. Dittmer about the level of administrative and overhead costs assigned to the T&D company. The Bench Analysis noted that while divestiture of the generation function will eliminate approximately one-third of the Company's operations, measured by investment, CMP assigned only 4.4 percent of total overheads and 5.3 percent of A&G expenses to the generation function as a result of the asset sale. Out of a total of 458 administrative employees, the Company has only projected a reduction of 18 positions as a result of divestiture. In addition, the Bench Analysis expressed concern that CMP failed to recognize any costs as allocable to new lines of business that the Company intends to enter, or to subsidiaries that the Company intends to grow. Finally, the Bench Analysis expressed concern with the Company's top-down approach, which looked at the costs that would be eliminated when it left the generation business, rather than what it would cost to run its T&D business.

Based on these concerns, the Bench Analysis presented three alternative methods for allocating CMP's administrative or overhead costs between its T&D and other operations. All three methodologies involved the allocation of overheads to generation, in addition to T&D and W&R, as a means of projecting the amount of costs which no longer were necessary or which were attributable to CMP's emerging lines of business.

The first suggested approach was to allocate all Company overheads in proportion to the direct costs of each business unit. This approach was seen by the Bench Analysis as the equivalent of a fully distributed cost allocation study. The second approach would make a similar allocation of A&G expenses but no reallocation would be made of investment-related costs, which are effectively treated as fixed and unavoidable. The third approach proposed in the Bench Analysis was to apply CMP's A&G loaders to direct generation costs as a way of identifying avoidable costs. The

Bench Analysis noted that the use of a loader is similar to the method by which CMP allocates overhead costs to its subsidiaries for support services. Subsequent to the release of the Bench Analysis, Tom Catlin, the primary author of the Cost Separation section of the Bench Analysis, indicated that after further consideration, he believed that the third methodology was not appropriate, and therefore he did not recommend that this methodology be considered by the Commission.

The Bench Analysis's two alternative approaches are summarized in the table below:

I. ALLOCATE TOTAL OVERHEADS BASED ON DIRECT COSTS ($000's)					
	Direct O&M Costs	Percent of Direct O&M	Allocated A&G Expenses	Allocated Investment Costs	Total Allocated Overheads
Generation	$51,430	29.62%	$13,259	$2,829	$16,088
Trans. & Distribution	112,084	64.56%	28,896	6,166	35,062
Wholesale & Retail	10,095	5.81%	2,603	555	3,158
TOTAL	**$173,609**	**100.00%**	**$44,757**	**$9,551**	**$54,308**
II. ALLOCATE A&G EXPENSES ONLY BASED ON DIRECT COSTS ($000's)					
	Direct O&M Costs	Percent of Direct O&M	Allocated A&G Expenses	Investment Costs per Company	Total Allocated Overheads
Generation	$51,430	29.62%	$13,259	$0	$13,259
Trans. & Distribution	112,084	64.56%	28,896	8,551	37,447
Wholesale & Retail	10,095	5.81%	2,603	1,000	3,603
TOTAL	**$173,609**	**100.00%**	**$44,757**	**$9,551**	**$54,308**

In its surrebuttal, the Company presented extensive testimony that A&G costs will not go down significantly as a result of divestiture, because such costs are driven primarily by customer, T&D investment and corporate related costs. The Company presented additional testimony by Caron/Dufour, joined by Peter Bedard and Kathleen Case, who testified about the nature of services provided by the Company's Information Services and Human Resources Departments. The Company also presented testimony from John Gillen, of Price Waterhouse, and Richard Levin of Mercer Management. As an example of a weakness in the Bench Analysis, Mr. Gillen pointed to the cost allocations that would result from a rise in the price of fuel. Mr. Gillen argued that from an accounting perspective it made no sense to continue to allocate costs on a fully distributed basis to a segment of the Company that no longer existed. The Company also asserted in its surrebuttal testimony that if a fully distributed approach were utilized as described in the Bench Analysis, it would be necessary to allocate A&G costs to the stranded cost segment of the business, which will continue to exist even after divestiture.

In support of his conclusion that CMP's allocation of overheads was reasonable, Mr. Levin noted that CMP's generation business was small when compared to national utility averages. In CMP's case, generation employees make up only about 10% of its workforce, while the national average is about 25%. CMP-owned generation plants only produced 21% of the Company's energy needs, while nationally company-owned generation plant produce about 75% of customer requirements.

In response to the Company's criticisms of the Bench Analysis, Mr. Catlin, along with Dr. Steven Estomin, also from Exeter Associates, Inc., performed a regression analysis "to examine the extent to which A&G expense is a function of generation, transmission and distribution, and general and intangible investment." The analysis was conducted using publicly available (FERC Form No. 1 Annual Report) data for those investor-owned utilities which generated 25 percent or less of electricity sold to customers.

The equation generated by the least squares regression analysis supported CMP's position that there is a fixed component of A&G and that A&G expenses are a function of T&D operations. Contrary to CMP's position, however, the equation also showed that A&G expense is a function of generation operations. Applying the coefficient developed for generation plant to CMP's 1996 generation investment resulted in an expected reduction of $9.3 million in A&G costs if generation operations were eliminated. During questioning by the parties, however, Messrs. Catlin and Estomin conceded that while <u>some</u> relationship could be established between generation operations and A&G expense, the particular <u>level</u> of A&G expense reduction for any particular company cannot be derived from the regression analysis.

Mr. Levin and Dr. Michael Donihue responded to the Exeter Analysis on behalf of CMP. Mr. Levin identified four principal problems with the regression analysis: (i) it lacked appropriate detail of CMP's A&G expenses, in that the study only examined A&G expenses in the aggregate as opposed to a detailed FERC account or functional analysis; (ii) the Exeter Analysis failed to properly identify the drivers of A&G expenses by oversimplifying and incorrectly characterizing the dynamics of A&G cost incurrence; (iii) the analysis failed to establish a causal link between level of plant investment and A&G expenses; and (iv) even using its own methodology, Exeter Associates incorrectly calculated the impact of divestiture on A&G expenses.

To illustrate the fallacy of the Exeter Analysis, Mr. Levin introduced a regression analysis that he had developed using the following explanatory variables: Electric Income Taxes Federal, Customer Accounts Receivable and Plant Materials and Supplies. Using these variables, Mr. Levin developed a regression equation that produced statistically significant results. According to Mr. Levin, this showed that a regression analysis, such as that produced by Exeter Associates, is virtually meaningless for purposes of determining the level of A&G costs that can or should be shed when divesting generation.

Dr. Donihue identified five principal shortcomings in the regression analysis or the use of the regression analysis:

- The model used by Exeter Associates is incorrectly specified in terms of its functional form and the included variables. The model is also misapplied in terms of the questions it is used to answer;

- There are significant problems with the sample Exeter Associates has chosen to use for their analysis. The 30 firms in the sample differ widely and are not representative of CMP in terms of their size or type of operations;

- The ways in which Exeter Associates has chosen to apply and interpret their empirical results are incorrect;

- The econometric methods used by Exeter Associates are simplistic and inappropriate for their sample;

- CMP is an outlier in the empirical results presented by Exeter Associates. Their model does a poor job at predicting the category of Administrative and General costs for CMP.

Dr. Donihue concluded that the study provided no basis to derive any conclusions about the effect of CMP's divestiture on the remaining level of A&G expenses for the T&D company.

C. <u>Analysis and Conclusion</u>

We start our analysis by recognizing that the cost separations issue in this case cannot be clearly placed in either of the test year or attrition categories, because the term "cost separations", at least as it is used in this case, incorporates both known and measurable type of test year adjustments and also attrition-type adjustments.

Under traditional ratemaking, the determination of a utility's revenue requirement is split into two distinct parts: test year analysis and the attrition analysis. In the test year analysis, a 12-month historic period is used as the base for predicting the Company's future rate year needs. The expenses, revenues and rate base from the historic period are then adjusted for known and measurable changes. To qualify as a known and measurable change, there must be a high degree of certainty that the change has occurred or will occur in the rate year, and it must be quantifiable with a high degree of accuracy. *Central Maine Power Company, Proposed Increase in Rates,* Docket No. 92-345, Order at 44 (Me. PUC Dec. 14, 1993). The attrition analysis goes beyond the test year and makes adjustments based on projections of revenues, expenses and rate base in the effective period. In our most recently concluded rate case, *Bangor Hydro-Electric Company, Proposed Rate Change*, Docket No. 97-116, we described the attrition analysis as follows:

> The identification of attrition or accretion is a complex process that is easier to define in concept than it is to quantify in practice. The standards that we apply to adjustments in the attrition analysis are slightly different than those applied to test year adjustment, where a strict known and measurable standard is observed. In an attrition analysis, the degree of precision by which proposed adjustments are evaluated and measured must, by their nature, take into account the lesser degree of certainty that surrounds projections of the items involved. An attrition analysis looks at a future period, the first rate effective year, and tries to project, using educated estimates and forecasting mechanisms, how that future will affect the operations of the utility.

Id. at 22.

We noted in *Bangor Hydro, supra.,* that there was no bright line between test year known and measurable change adjustments and attrition adjustments. In trying to project T&D expenses for a rate year commencing on March 1, 2000 based on a 1996 test year for an integrated utility, that line at times, seems indistinguishable. For purposes of our analysis, we will first look at the four discrete cost separation adjustments proposed by the OPA and then we at the overall projections for T&D A&G costs provided by the Bench Analysis, the Company and the OPA.

1. <u>Research and Records Expense</u>

Based on an overall test year expense of $954,000, the Company initially proposed to include $756,000 for the Research and Records Department in its T&D revenue requirement. Mr. Dittmer urged that Research and Records be reduced by $500,000 to reflect the downward trend in expenditures for this department. The Company essentially has accepted the OPA witness' recommendation and reduced test year expenses downward based on its 1998 budget of $547,000, of which $433,000 is allocated to the T&D company.

The difference between the OPA witness' recommendation and the Company's position is *de minimis* ($73,000). The Company's 1998 budget appears reasonable based on historical levels of spending, and we, therefore, accept the Company's proposed downward adjustment of $323,000 for this expense item.

2. Governmental Affairs Costs

Mr. Dittmer, in his direct testimony, proposed that the Commission make a $461,000 adjustment to eliminate from CMP's proposed expenses two-thirds of the test-year Governmental Affairs Department expense. CMP reviewed Mr. Dittmer's analysis, and as a result, eliminated an additional $369,062 of Governmental Affairs Department expense from the T&D company in its separation study. In his surrebuttal testimony, Mr. Dittmer accepted CMP's proposed adjustment, and we also adopt the adjustment.

3. Legal Expenses

OPA witness Mr. Dittmer also proposed in his direct testimony a downward adjustment of $84,000 for legal retainer fees. The adjustment was based on the ratio of the Company's generation specific outside legal costs to total test year outside legal costs. Mr. Dittmer's ratio was revised downward to $68,000 in response to CMP's suggestion that the adjustment should be based on all legal fees.

The Company responds that the OPA's adjustment is based on one statement by the Company's General Counsel "that the Company probably would be renegotiating its legal retainer fees given the downsized company that will exist following divestiture." The Company thus argues that there is an insufficient basis to make the adjustment proposed.

While we agree generally with Mr. Dittmer's conclusion that expenses of this nature will be going down, the proper methodology is to address the issue in the attrition type separations adjustment discussed in subsection 5. We, therefore, will not adopt the discrete adjustment proposed by the OPA that outside legal costs should be reduced by $68,000.

4. Advertising Expense

The OPA recommends that the Commission reduce the Company's advertising expense by $1,269,771 so that only $892,000 in advertising expense remains in its adjusted test year. The OPA's recommendation is based on a view that the Company should be required to justify "from the ground up" any prospective advertising expenses that go beyond traditional "safety" advertising and advertising that delivers basic customer information. The OPA claims that to develop a reasonable estimate of the level of advertising expenses for a T&D utility company, the following question should be asked: "What advertising expenditures are necessary on an ongoing basis for a monopoly supplier of T&D service?" The OPA argues that only the following types of advertising should be supported by the T&D customers:

- Bill inserts,
- Informing customers of their rights regarding utility services,
- Educating customers to understand their bills and/or how to read their meters; and
- Safety related.

The Company points out that it will remain the primary link between over 500,000 customers and their electric supplier of choice; that it will continue to have responsibilities in the areas of business development, energy conservation, customer retention, customer service and customer information and education; and, in order for it to carry out its functions in a responsible and effective manner, a properly financed and well-thought out advertising program must support it. Finally, the Company claims that Mr. Dittmer's criteria are not consistent with established Maine practice, prior rulings of the Commission and the Commission's regulations dealing with advertising expenses, and that Mr. Dittmer admitted during cross-examination that he had not reviewed any Maine precedent on the subject.

We accept the Company's proposed T&D advertising expense level of $1,977,000 for the rate effective year. We agree that the level of advertising expense should be developed from the bottom-up, and we accept that the Company's approach as presented in the surrebuttal testimony of Dumais/Cornwall meets this criterion. At this point in the restructuring process, it is not possible to predict how the market for electricity will take shape, who will be marketing to customers or how such marketing will be done. It is reasonable to assume, however, that as the T&D utility, CMP will continue to have a major role in communicating with its customers regarding electric restructuring and, where appropriate, in promoting its product. After reviewing the Company's categories of advertising expense presented in its bottom-up approach, we accept the Company's $1,977,000 advertising expense amount for the rate effective year.

5. <u>Projection of T&D A&G Costs</u>

The Company has produced extensive evidence in support of its projection that indirectly assigned T&D A&G costs will only be reduced by $2,370,000 in the rate year. The Company may well be correct that A&G costs will only be reduced by the level projected in its study. We find, however, that the Company has overallocated its total company A&G costs to the T&D utility. We will thus reduce the Company's proposal based on the evidence before us.

The Company argues that A&G costs should be allocated based on the benefits they provide. Because such costs are essentially unavoidable and the generation function will no longer benefit from such services, the costs must fall to the remaining entities receiving the benefits, primarily the T&D company. In its cost allocation study, however, the Company does not account for the company resources and benefits provided by the holding company and the OSD in support of the Company's efforts to grow its non-core and new lines of businesses. The Company argues that there is no credible evidence to suggest that these activities will require significant resources. We disagree. The Company's own business plans provided in this case demonstrate that the Company anticipates devoting considerable resources to expand these businesses, and that these growth areas will require significant support from A&G type functions.[4]

The electric utility industry is in the midst of unprecedented changes. The Company has described the current changes as the most significant since the onset of regulation in 1913. To the Company's credit, it has taken major steps to transform itself in response to these changes. The Company has reorganized into a holding company structure and has created several new subsidiaries to enter into a variety of new businesses. It is fair to conclude that CMP expects significant growth in its non-core businesses between 1996 and the 2000/2001 rate effective year. This will require increased A&G support, and the cost should not fall to the T&D company's core ratepayers. The Company's business plans recognize the impact that the growth of the non-core businesses will have on A&G services. The Company's cost separations study, however, ignores that impact.

We also conclude that we cannot rely on the regression analysis submitted by Mr. Catlin and Dr. Estomin of Exeter Associates on October 2, 1998 to establish the precise level of A&G cost allocations. As noted above, Dr. Estomin testified that the equation developed by his regression analysis could not be used to produce a specific expected reduction in A&G expenses for a specific company nor could the equation be expected to produce a reasonable range of reductions. Dr. Estomin testified the equation was only intended to indicate that there was a significant relationship between company-owned generation plant and A&G expense. It appears that this conclusion is not contested by the Company. The issue that we must decide is what level of reduction in A&G expenses should be incorporated into setting the T&D Company's revenue requirement for the rate year commencing March 1, 2000. Because the Exeter analysis does not provide an answer, we must analyze the fully distributed cost separations analysis presented in the Bench Analysis, and compare it to the Company's proposed allocation.

At the hearings, Mr. Caron testified that if the generation function were not being divested, the approach put forth in the Bench Analysis would be reasonable. The two central criticisms made by the Company of the Bench Analysis's cost separations study were that (1) the fully distributed separations approach underallocates costs to the T&D function, because it does not adequately recognize the

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[4]Because of their confidential nature, we do not recite in detail the Company's plans to grow its non-core businesses.

cost economies of scope that will be lost when the generation function is divested, and (2) the Bench Analysis approach does not recognize the fixed nature of many of the Company's A&G costs (such as office space) which cannot be avoided.

We agree with the Company's assertion that it will not be able to avoid fixed-type expenses immediately after the generation function is divested. While, in the long run, it is reasonable to assume that the Company will be able to align its A&G investments with the scope of its business, we accept that such changes are not likely to occur during the rate effective year which begins in a little over one year from now. Alternative Approach #2 in the Bench Analysis, which assumes that fixed overheads such as buildings and equipment cannot be avoided in the short term, represents an attempt to address this concern. When this approach is used and fuel expense is removed from the allocation process, as the Bench concedes it should be, the amount of overhead allocated to the T&D company is $40,548,000, or $7,524,000 less than the Company's allocation.

The Company asserts that because it has not divested all of its generation-related functions, specifically its nuclear interests and QF contracts, the Commission should assign a portion of A&G costs to stranded costs. However, because stranded costs are largely based on market prices, an assignment as suggested by the Company would result in higher A&G allocations to stranded costs simply because of the occurrence of an external event, i.e., an increase in market price, which has no impact on the overall level of A&G costs. Thus, similar to the Company's reasoning on why fuel costs should be excluded from the analysis, we do not accept the Company's recommendations on allocating A&G expenses to stranded costs. To the extent that there are costs associated with QF contract administration, they should be offset by our decision not to allocate costs away from the T&D company based on fuel expense where similar administrative costs will now be avoided by the T&D company.

From the outset of the restructuring debate we have recognized the possibility that some economies of scope would be lost initially when integrated public utilities were split into smaller units. We also recognized the potential that any lost economies of scope could be more than offset by the benefits which would be gained by moving to a competitive generation market. No party has been able to quantify the level of these potentially lost economies. It is quite likely, however, that these economies will be regained over time, at least in the case of CMP, as it expands its existing, or enters into new, non-core business ventures.

The cost separations issue contains some of the most difficult questions in this case because of the evolutionary nature of the electric industry and of CMP itself. We do not know for certain what the organizational structure of CMP will be or what lines of business outside of T&D the Company will actually pursue. We agree with the Company's assertion that, at least during the initial phases of restructuring, many of the Company's current A&G costs will be unavoidable. It is also possible that certain areas will see increasing costs as CMP adjusts to its role as an "intermediary" between customers and suppliers. Finally, the level of CMP's non-core activities remains uncertain, and thus, the portion of costs that should be allocated away from the T&D operations requires informed judgment on our part.

We believe that we will be in a much better position to address the cost separations issue in our next CMP rate case when we actually have a record of T&D activities and expenses upon which to base our decision on. Until then we must make do with the projections that have been provided by the Advisory Staff.

We will first adjust the overall level of A&G expense to account for the findings contained in subsections C(1), (2), (3) and (4) above. We will then adjust the Company's proposed allocation of costs to T&D downward by 4%, based on our judgment that the arguments put forth by CMP support an allocation that is higher than that proposed in the Bench Analysis approach #2 as corrected to remove fuel costs, but not as high as CMP contends. The difference between the two proposals is about 15.65% ($7,524,000 divided by $48,072,000). We will require that the difference be reduced to 4%, or $1,923,000 lower than the Company's proposed amount (.04/.1565 * $7,524,000).[5]

We realize that some calculation difficulties may arise because of changes to amounts that have occurred in the late stages of this phase of the case, or that may occur because of updates in Phase II. If any of those require a finding by the Commission, CMP should bring them to our attention in Phase II. The basic premise of our finding is that, after adjusting the specific categories included on Table 1 of the Bench Analysis, the remaining amounts allocated to the T&D revenue requirement should be reduced by 4%.

III. TEST YEAR

We have reviewed the Company's base period revenue requirement for its T&D Company. We analyzed each of the proposed adjustments to expenses, revenues and rate base to determine its appropriateness as either a normalizing adjustment or a known and measurable adjustment to the test period.

As a result of that review, the following adjustments are either not contested, or are not contested but must be updated in Phase II:

Electric Lifeline Program
O'Connor Hazardous Waste Site Clean-up
Amortization of Reacquired Debt and Preferred Stock
Deferred Flood and Management Audit Cost
Uncollectible Accounts Expense

[5]This reduced amount will be used in the revenue requirement calculation.

Late Payment Revenue
Tax Audit Expense
Other Electric Operating and Rent Revenue
Projected Loss on Required Debt

The remainder of this section deals with the areas of the revenue requirement that are contested.

A. Statement of Financial Accounting Standards No. 106 (SFAS No. 106)

In 1990, the Financial Accounting Standards Board issued SFAS No. 106 requiring that the Company change its accounting method from a cash basis to an accrual basis for post-retirement benefits other than pensions, more commonly known as Other Post-Employment Benefits (OPEB). These benefits are primarily health care and life insurance. Under SFAS No. 106, the Company must recognize the present value cost of future benefit payments as the benefits are earned by the employees. The accounting pronouncement basically requires that the proper amount of liability be recognized on the balance sheet, and the current period cost of the benefits be determined through actuarial means.

As a result of SFAS No. 106, CMP has proposed adjusting test year net expense downward by $351,000 and adjusting rate base downward by $7,245,000 to reflect the recovery of deferred SFAS No. 106 amounts resulting from the phase-in of the SFAS No. 106 expense into rates, and to reflect the expected ongoing annual expense amounts. In developing these test year adjustments, the Company went through a three-phase analysis. First, it determined the expected rate year SFAS No. 106 expense level. This analysis, the Company claims, specifically recognized the effects that divestiture will have on ongoing SFAS No. 106 expense. Second, the Company used its separation study to allocate projected rate year SFAS No. 106 costs to non-T&D Company operations. In this manner, the Company claims that the total rate year's SFAS No. 106 costs are allocated among business units. Finally, the Company compared test year to rate year T&D Company SFAS No. 106 costs to arrive at its adjustment.

In Phase I of its analysis to determine its rate year SFAS No. 106 expenses, the Company proposes to continue the $1,535,000 amortization approved by the Commission in Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan, Docket No. 97-599, Order Approving Stipulation (M.P.U.C. June 27, 1997) for the recovery of the deferred asset created while the Company phased into rates the effects of SFAS No. 106. The Commission also approved, in that Docket, the recovery of $10,800,000 for the current period (ongoing) OPEB costs. The Company, however, has revised this current period amount with a new estimate of $9,400,000. The new estimate reflects the most current actuarial study performed by its consultant, Actuarial Sciences Associates, Inc. (ASA), prior to the sale of its generating assets and the accompanying reduction in its employee population.

Finally, the Company claims that SFAS No. 88, "Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination of Benefits," requires immediate recognition of a "curtailment" for any event that eliminates ten percent (10%) or more of expected future employee service time. At this time, ASA estimates the curtailment expense associated with the elimination of generation employees from the plan to be $9.5 million. It is CMP's intention to fund the entire costs of the curtailment once the asset sale is complete. If the funding is approved, the Company projects earnings in the fund during the rate year of approximately $2,088,000.

The Company proposes to apply the $2,088,000 interest earned in the trust fund against the $9,400,000 of projected current period expense. Beginning in March 2000, the Company proposes to treat all OPEB current period expenses as payroll overheads (instead of claims actually paid during the year). This treatment would result in an estimated rate year expense level of $5,965,000.

To summarize the first phase, the Company’s analysis projects an annual amortization of deferred SFAS No. 106 expense of $1,535,000 and an ongoing SFAS No. 106 expense of $5,965,000.

The second phase of the Company's analysis allocated rate year SFAS No. 106 expense to its various business units. The Company asserts that it used the methodology employed in the separation study performed by Mr. Caron and Ms. Dufour. As a result, $1,401,300 of the $1,535,000 of rate year amortization expense was allocated to the T&D Company. In addition, $5,532,000 of the $5,965,000 of ongoing SFAS No. 106 expense was allocated to the T&D Company.

In the final phase of its analysis, the Company compared its proposed rate year amount of SFAS No. 106 expenses to its test year amount that included $767,000 of amortization expense related to deferred SFAS No. 106 expense amounts and an ongoing SFAS No. 106 expense amount of $6,517,000. When compared to the T&D Company’s projected rate year amortization expense of $1,401,000 and an ongoing SFAS No. 106 expense of $5,532,000, the Company proposes a downward adjustment to test year net expense of $351,000.

There is also a rate base impact from this adjustment. The Company claims that the average test year deferred SFAS No. 106 regulatory asset balance of $22,455,000 is being amortized at an annual rate of $1,535,000, the level approved by the Commission in Docket No. 97-599. This amortization will reduce the average deferred balance by $5,407,000 through the rate year. However, over this same period of time, the associated average deferred tax asset balance will increase by $1,425,000. The net effect is a decrease to test year rate base of $3,983,000.

The average test year SFAS No. 106 liability balance of $27,219,000 will increase as plan participants earn current benefits, and decrease from both claim payments and contributions to the external trust fund. Based on projected annual SFAS No. 106 benefits earned, annual benefit payments, and trust fund contributions, the Company projects that the average rate year SFAS No. 106 liability will be $30,481,000. The net effect is a decrease to test year rate base of $3,262,000. Therefore, the Company proposes a downward adjustment to rate base in the amount of $7,245,000 ($3,983,000 + $3,262,000).

The Bench Analysis expressed concern that the Company’s SFAS No. 106 cost calculations did not reflect the impact of the Company's generation asset sale, and that the Company’s initial filing also reflected pre-divestiture and post-divestiture OPEB costs on an inconsistent basis. The latter concern has been corrected by the Company but the former concern will not be corrected until the Company's generation assets have been sold and a new actuarial analysis by ASA can be concluded. Therefore, the amount of this adjustment must be updated by the Company in Phase II when the new ASA actuarial study is completed after the sale of its generating assets.

Despite the need for an updated actuarial study, we can make one important determination regarding SFAS 106 costs. We accept the proposed level of amortization expense ($1,535,000) related to the recovery of the deferred SFAS No. 106 regulatory asset. We approved the deferred asset and related amortization in Docket No. 97-599 with the expectation of full recovery by year 2012.

While we approve the methodology used by the Company to calculate the proposed SFAS 106 adjustment, we cannot approve the exact amounts, because in large part, they depend on the allocation of test year and rate year expenses to non-T&D Company operations. We will base the allocation on the separations methodology adopted in Section II above. CMP’s T&D expense can then be determined after the following amounts are known: (1) the actuarial estimate of the rate year level of ongoing SFAS No. 106 expense; (2) the final actuarial determination of the SFAS No. 106 curtailment expense; and (3) the estimate of rate year interest income earned by the trust. These updates should occur in Phase II of this proceeding.

B. Workers' Compensation

During 1995, the Company's external auditors, Coopers and Lybrand (C&L), identified the asset on the Company's balance sheet for workers' compensation as one that required additional evidence of recoverability in order to meet the criteria of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." Because the Company was unable to provide sufficient evidence of recoverability, C&L required the Company to provide a reserve for the possible non-recovery of the workers' compensation asset. The Company claims that in Docket No. 96-599, *Central Maine Power Company, Annual Price Change Pursuant to the Alternative Rate Plan*, the Commission permitted recovery of the $6,400,000 deferred workers' compensation asset over approximately nine years, thus creating a regulatory asset.

The Company's adjustment comprises two parts. First, it increases the annual amortization related to the recovery of the deferred asset balance to reflect a full year's amortization of $700,000. The Company began amortizing the costs on July 1, 1996 and recorded $350,000 of amortization expense during the test year. This adjustment increases the annual expense by an additional $350,000 to reflect a full year of expense during the rate year. The amortization of the costs through the rate year, net of the increasing deferred tax asset balance, and including an annual amortization of $700,000, increases test year rate base by $271,000.

The second portion of the adjustment reverses two accounting adjustments that decreased the test year expense amount by $4,806,000. The Company claims that the Commission's Order in Docket No. 96-599 reaffirmed reinstatement of the $6,400,000 regulatory asset, allowing reversal of the reserve established in 1995 against the asset. The elimination of the reserve in 1996 reduced worker's compensation expense by $6,400,000. Also during 1996, the Company increased its workers' compensation reserve by $1,594,000, resulting in an equal increase in workers' compensation expense. These test year accounting entries do not reflect the expected rate year expense level, and they have been reversed. The effect of these reversals is to increase test year expense by $4,806,000.

The Bench Analysis agreed that the net reversals to the 1996 test year expense were appropriate adjustments, and we accept them for inclusion in the T&D revenue requirement. The Bench Analysis, however, recommended that the Commission reject the Company's continued amortization of its workers' compensation assets after March 2000, because the Commission's Order in Docket No. 96-599 did not specifically allow such amortization. As discussed below, we disagree with the Bench Analysis and allow the continued recognition of a regulatory asset and the accompanying amortization of worker's compensation costs.

The Company claims that the conclusion in the Bench Analysis hinges on an incorrect interpretation of the Commission's Order in Docket No. 96-599. The Company maintains that the Bench Analysis based its conclusion regarding the recovery of the workers' compensation regulatory asset on the first sentence of the second paragraph of the Order that says:

> In addition, the Company indicated that, after the conclusion of the ARP, it would not seek to recover any unamortized balance related to the workers' compensation regulatory asset as a stranded cost, should recovery of stranded costs be authorized by the Commission in the future.

Docket No. 96-599 Order at 8.

The Company argues this statement is incorrect and that during a conference of parties held on June 6, 1996, in Docket No. 96-599, Mr. Cohen, then representing the Commission's Advocacy Staff, stated:[6]

> "we do accept their [CMP's] revised proposal which would be to allow the reinstatement of the asset without the specific pass-through of the $700,000 amount for that recovery and the recovery would be done through some type of use of the monies allowed for the FAS 106 expense and then we would just add that it would be our understanding that, at the end of the ARP, there would be no amount to be recovered through a stranded cost recovery if there was -- if CMP was not able to use that amount to offset the $6.4 million."

The Company claims that Mr. Cohen's statement clearly shows the Advocacy Staff in that case understood the Company's proposal to recover the workers' compensation costs over a 9-year period by using savings from the SFAS No. 106 recovery. CMP asserts that the Commission understood the Company's intent regarding the recovery of costs through the application of SFAS No. 106 savings.

The Company argues that it is not seeking recovery of the regulatory asset as a stranded cost in this proceeding. CMP only seeks to continue to apply $700,000 of achieved SFAS No. 106 savings to the recovery of the workers' compensation regulatory asset, in a manner consistent with its interpretation of the Commission's decision in Docket No. 96-599.

Finally, the Company claims that Docket No. 96-599 placed the risk of recovery of the workers' compensation regulatory asset on the Company by (1) not providing specific rate recovery for the regulatory asset; and (2) allowing the Company to recover the asset only to the extent it achieved its projected SFAS No. 106 savings. Therefore, if the Company did not achieve savings in its SFAS No. 106 expense, it would not have the authority to recover the workers' compensation deferred asset. The

[6]Based on his prior participation as an advocate, Examiner Cohen recused himself from participation on this issue by way of a memorandum of recusal dated October 9, 1998.

Company asserts that the language prohibiting recovery of the unamortized balance as a stranded cost ensured that if the Company did not achieve savings that could be applied to the recovery of the regulatory asset, it would not be able to seek a different means of recovery once the ARP concluded. The Company points out that unless it could demonstrate to its auditors that it did and could, in fact, achieve savings in its SFAS No. 106 expense, the Company would have been unable to create the regulatory asset in the first place.

Much of the controversy over the continuation on CMP's books of a regulatory asset for deferred workers' compensation costs involves the interpretation of our order in Docket 96-599. We do not see the language in that Order as prohibiting--nor did we intend to prohibit--the continuation of a regulatory asset. Instead, the burden was placed on the Company to demonstrate that it had achieved sufficient savings in its SFAS 106 expenses to allow the amortization to continue. The Bench Analysis appears to invoke a too literal interpretation of the previous order. As we move into the restructured electric environment, we believe we should set revenue requirements as accurately as possible based on the information presented in the record.

We have already examined the Company's proposed rate year level for SFAS 106 costs. While the actual amount is subject to update in Phase II, and the amount that will be recovered through T&D rates will be determined by application of the separations methodology that we order, we have found the Company's basic method for determining rate year SFAS 106 expenses to be reasonable. Thus, it may be inferred that all SFAS cost savings have been "captured" in that adjustment.

Similarly, the Bench Analysis found no substantive problems with the manner in which the Company's rate year workers' compensation costs were determined. Absent our prior Order, there likely would be little dispute over the proper methodology for calculating this expense category. The Company is in the middle of a transition period from a pay-as-you-go expense basis to full accrual accounting. Nothing in the language of the Docket 96-599 Order reflects an intent by the Commission to prohibit recovery of reasonable workers compensation deferred transition costs or to disallow continued recognition of a regulatory asset for the unamortized transition amount. Therefore, subject to updating the amounts after the sale of assets and subject to any other modifications needed to incorporate new projection assumptions, we approve the Company's proposed treatment of workers' compensation amounts for the rate year.

C. Curtailment Costs

Curtailment costs are costs which will be incurred by CMP as a direct result of terminating employees due to the sale of its generation assets. Under the provisions of SFAS No. 88, Employers' Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits, and SFAS No. 106, Employers' Accounting for Post-Retirement Benefits Other than Pensions, a curtailment is an event that significantly reduces the expected years of future service of present employees or eliminates for a significant number of employees the accrual of defined benefits for some or all of their future services. Actuarial Sciences Associates, Inc. (ASA) estimated net curtailment costs of the pension and medical plans at $5.5 million, consisting of an estimated loss associated with curtailment of the medical plan at $8.9 million and a gain associated with curtailment of the pension plans at $3.4 million.

The curtailment costs claimed by CMP are legitimate costs associated with the divestiture of the Company's generation assets and the related termination of generation-related employees. We authorize CMP to establish a regulatory asset once the costs are actually incurred. The Company should propose a recovery mechanism through T&D rates during Phase II of this proceeding.

D. <u>Employee Transition Costs</u>

Section 3216 of Title 35-A requires investor owned utilities to develop a plan for providing transition services for eligible employees. The term "eligible employee" means any employee of an electric utility who is employed by the utility on January 1, 1998 and is laid off, either by the investor owned utility or the new owners of the divested generation facilities, due to retail competition on or before December 31, 2001. 35-A M.R.S.A. § 3216(1)(A), MPUC Rules, Chapter 303 § 1(B)(2).

The transition services plan must provide for out-placement services, retraining, and continued health insurance for two years, and severance pay equal to two weeks of base pay for each year of employment. The plan may also include provisions for early retirement programs. While section 3216 does not require the Commission to formally approve an employee transition plan, the law clearly contemplates Commission review by requiring a utility to file its employee transition plan before the utility takes final action that causes an eligible employee to be laid off, or at least 90 days prior to the start of retail access. 35-A M.R.S.A. § 3216(3).

On January 20, 1998, CMP filed its proposed Employee Transition Plan (Plan) and requested that it be approved by the Commission. On March 12, 1998, the Commission found that CMP's proposed Plan was consistent with the requirements of section 3216. *Central Maine Power Company, Request for Approval of Employee Benefits Plan*, Docket No. 98-050 (Me. P.U.C. March 12, 1998). The Commission noted, however, that:

> [T]his finding should not be construed as a finding that all of the costs associated with the proposed Plan will be recovered from ratepayers pursuant to section 3216(5). While section 3216(5) requires recovery of the reasonable costs of those benefits mandated by the statute from ratepayers, recovery of the costs of any benefits which

exceed the statutory requirements will be determined either in the rulemaking on this issue or in an appropriate ratemaking proceeding.

The Commission's Employee Transition Benefits Rule (Chapter 303), adopted on July 1, 1998, provides that a utility's employee transition plan may include provisions for portability of accrued early retirement benefits and other discretionary benefits. The utility, however, has the burden to justify the recovery of the costs of any such benefits in rates.

We now address whether the specific components of CMP's employee transition costs should be recovered from ratepayers in light of the standards discussed above.

1. Enhanced Severance Benefits

In its original filing, the Company estimated the costs associated with the severance benefits mandated by section 3216 to be $2.0 million. This estimate was based on a projection that 40 employees would be laid off as a result of restructuring. The Company has subsequently revised its projection downward to 20 employees and revised its cost estimate to $1.0 million. This overall estimate is based on an average cost per laid-off employee of $50,000. The per employee cost breaks down as follows:

Severance	$23,100
Medical & Dental	$12,800
Conversion of Life Insurance	$ -0-
Out-placement	$6,000
Education & Retraining	$7,500

We find that the per employee costs claimed by the Company for the severance benefits mandated by the restructuring statute are reasonable and represent incremental costs to the Company. The Company should update the cost estimates per employee and provide evidence of the number of employees actually laid off in Phase II. The Company's Phase II filing should also include a proposal for recovery of these costs in T&D rates.

2. Early Retirement Benefit Enhancements

The Early Retirement Benefit Enhancements (ERBE) consist of three separate programs: the Enhanced Pension Benefit (EPB); Permanent Eligibility Enhancement (PEE); and Post-Retirement Medical Benefit (PRMB). The EPB removes the "early retirement reduction factors" ordinarily applied to employees who retire before age 62 and is available to employees who are 50 or older and have completed 10 or more years of service with CMP or its subsidiaries as of December 31, 1998. The

PEE reduces the "early reduction factor" for employees who terminate employment with CMP prior to reaching age 55 and is available to employees who have 20 or more complete years of service with CMP or its subsidiaries by December 31, 1998, and who are not eligible, or have declined, the EPB. Finally, the PRMB allows employees to participate in the Company's Post Retirement Medical Care Plan if their age and years of service equals 70 as of December 31, 1998. According to CMP, this benefit provides for greater access to post-retirement medical benefits for employees who will not have the ability to accumulate enough service with a subsequent employer to qualify for a comparable benefit.

Unlike the ESB package of benefits, the Early Retirement Package is available both to employees who are laid off as a result of restructuring and to those who are transferred to the buyer or transferred to a CMP subsidiary[7] as a result of divestiture. The benefits of the two packages cannot be duplicative, and eligible employees must decide which of the packages they want to receive.

In deciding the issues of whether CMP has adequately carried its burden and whether the costs associated with these discretionary programs should be borne by CMP's ratepayers, we must look at the underlying purposes of section 3216. In *Public Utilities Commission, Utility Employee Transition Benefits (Chapter 303),* Docket No. 98-328, Order Adopting Rule, we found that the Legislature anticipated that changes in the industry structure and the divestiture of generation assets might cause current utility employees to lose their jobs, and so we required utilities to provide, and ratepayers to pay for, a certain package of benefits. This package of benefits essentially provides a "safety net" for employees who lose their jobs due to restructuring. We believe it is appropriate to require ratepayers to pay for an extension of benefits where there has been a showing that employees will be unduly harmed if additional benefits are not provided.

Under CMP's Plan, an employee who is laid off from CMP and not transferred may, if eligible, opt for the benefits provided under the ERBE program. We believe, under our "undue harm" standard, that it is appropriate to allow the recovery from ratepayers of costs associated with the ERBE program for those long-term employees of CMP who are actually laid off late in their careers from utility employment as a result of restructuring. Whether the costs associated with the ERBE program are ultimately recoverable from ratepayers may be affected by the agreement(s) between the Company and the International Brotherhood of Electrical Workers (IBEW) at the time we approved the Company's plan. Therefore, we will require CMP to provide a copy of the signed agreement(s) to us during the Phase II

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[7]It is our understanding that the cost estimates provided for these transition programs are for employees who either are laid off or transferred as a result of the asset sale. Under 35-A M.R.S.A. § 3216(1)(A), employees transferred within a Company are generally not eligible employees for transition benefits. CMP should identify any costs incurred for employees transferred within the Company as part of its Phase II filing.

portion of this proceeding. The Company and the IBEW may also provide any other information related to the intent of the parties regarding Commission approval of the Plan. Among other matters, we wish to know whether Commission approval of the recovery of costs associated with the Plan was a requirement for the agreement to take effect.

At a technical conference, Mr. Marsh, the Company's CFO, stated that the EPB program was also necessary to prevent transferred employees from being penalized as a result of the "hockey stick" effect. As explained by Mr. Marsh, the "hockey stick" effect occurs because pension benefits accrue at a greater rate in later years of employment. An employee who changes employers at mid-career will thus lose some amount of pension benefits. Since that time, CMP has clarified that FPL would be giving credit to CMP employees for their service with CMP. Therefore, transferred CMP employees will not suffer the "hockey stick" effect upon transferring to FPL, but CMP argues that it is appropriate to provide the EPB since these transferred employees have lost the ability to retire from CMP. FPL's providing credit for their time of service means that CMP employees who transfer to FPL will not suffer any adverse financial impacts as a result of restructuring. Employees may opt for an EPB from CMP, in which case FPL would not give credit for prior services at CMP. We will not at this time approve the ERBE plan for those employees who transfer to the buyer of CMP's generating assets or who transfer to another CMP subsidiary.

We do not now decide whether CMP has justified including the costs associated with the PRMB in rates. As part of the asset sale agreement, CMP is required to pay $1 million to compensate FPL for the costs incurred by FPL in giving CMP employees who transfer to FPL full credit for their service at CMP for purposes of accruing post-retirement medical benefits. As discussed in Part 2, Section II(B), we have allowed CMP to offset this amount with a portion of the asset sale proceeds. Given FPL's statements concerning the adequacy of its benefit packages and our allowance of costs to ensure that CMP employees receive credit for their CMP service, we cannot find that the benefits of the PRMB package are needed to prevent undue harm to CMP's employees. We will, however, as part of the Phase II proceeding, allow CMP to provide further information as to what additional benefits employees who transfer to FPL will receive as a result of the PRMB and whether these benefits are necessary to prevent employees who transfer from being unduly harmed. As discussed previously, we also want to examine the ETP agreement between the Company and the IBEW.

CMP's Phase II filing should include a proposal for recovery in its T&D rates of any discretionary benefit costs that might be approved at the conclusion of the case.

E. Cash Working Capital

The Company claims that no party has contested the projected amount of Cash Working Capital (CWC) and, therefore, it should be accepted by the Commission. This statement is not entirely correct. While it is true that no party has contested the methodology presented by the Company to develop its CWC, the actual CWC balance depends on the level of the various revenue requirement expense adjustments. Therefore, we accept the Company's methodology, but the exact CWC allowance must be determined by using the expense amounts found reasonable in the other parts of this Order, including the updates either permitted or required to be made in Phase II.

F. Transmission

The Company has stated that most of its revenue requirement for transmission operations is recoverable under tariffs approved by FERC. Because of the numerous changes to the Company's operations and the adoption of transmission pricing policies by NEPOOL subsequent to the test year, CMP states that transmission costs will grow faster than its revenues. The events causing the decrease to rate year revenues include the closing of Maine Yankee and the sale of the Wyman units, resulting in less wheeling revenues for CMP. The increased costs are associated with the implementation of the FERC's open access transmission tariff policies.

FERC's transmission policies and NEPOOL's transmission rules continue to evolve. As a result, we cannot now determine CMP's transmission-related revenue requirement. Moreover, as discussed in Part 3, we conclude that FERC has asserted jurisdiction over transmission rates, terms, and conditions when generation is unbundled and offered as a separate product. Accordingly, it appears that CMP must obtain FERC approval of its transmission revenue requirements. The Commission will continue to monitor the transmission pricing and cost recovery implications as federal and regional policies develop.[8] Due to the current uncertainties, CMP should update its rate year transmission revenue and expense projection in Phase II.

IV. ATTRITION

An attrition analysis examines the relationship among the various pieces of the ratemaking equation (that is, the Company's revenues, expenses and rate base) as the period under consideration moves from the test year to the rate-effective period, or rate year. While the adjustments to the test year must meet the known and measurable standard, attrition adjustments in general possess less certainty, and so require a higher level of scrutiny before they are included in a utility's revenue requirement calculation. In spite of that uncertainty, the Commission has typically performed an attrition analysis as part of its rate case proceedings to attempt to ascertain whether the utility will have a reasonable opportunity to earn its allowed return during the first

[8]As discussed in Part 3, we will open an investigation to explore, among other things, the implications of federal and regional policies on CMP's transmission pricing and corresponding tariffs.

year that new rates will actually be in effect. In fact, the Law Court has found this process to be a proper part of the Commission's ratemaking activities. See e.g., *Central Maine Power v. Public Utils. Comm'n*, 455 A.2d 34, 40 (Me. 1983); *New England Tel. & Tel. Co. v. Public Utils. Comm'n*, 448 A.2d 272, 312 (Me. 1982); *New England Tel. & Tel. Co. v. Public Util. Comm'n*, 390 A.2d 8, 47 (1978); *Maine Water Co. v. Public Utils. Comm'n*, 388 A.2d 493, 497 (Me. 1978); and *Central Maine Power Co. v. Public Utils. Comm'n*, 382 A.2d 302, 316, 318 (Me. 1978).

The reason for conducting an attrition analysis is clear: because rates are set for a future period, the Commission must assess whether those rates are fair to the Company and to its ratepayers. Specifically, the Commission must determine if the rates will give the utility a reasonable opportunity to earn its allowed return, but no more than such reasonable opportunity. The ratemaking process, being prospective, always involves some degree of uncertainty. This case, however, contains far more uncertainty than past proceedings for several reasons. First, the utility for which rates are being set is significantly different from the one that exists today and for which rates have been set in the past. CMP has been, and until March, 2000 will remain, an integrated utility selling power to its customers. Beginning on March 1, 2000, the Company will become a conduit of that power from producers to end-user customers. It is in the process of selling its generating plants and deciding in what lines of business it wants to invest beside its utility T&D operations. Thus, we are faced with attempting to set revenue requirements for a new type of utility.

In addition, because of the statutorily imposed requirement to complete the revenue requirements portion of the electric rate cases by July 1, 1999, CMP has used calendar year 1996 as the test year. While we find that the test year selected is reasonable, its use in setting rates necessitates a greater degree of estimation since the rate year will not begin until three years and two months after the end of the test year. Therefore, the attrition analysis in this case takes on even greater importance and poses even more difficulty than in past proceedings. The bases for projecting revenue, expenses and rate base into the rate effective period must be carefully examined.

A. <u>O&M Expenses</u>

1. <u>Positions Before the Commission</u>

There is no dispute that the starting point for the analysis of attrition is the test year as adjusted for known and measurable changes. Thus, any changes to the calculation of the test year revenue requirement will impact the determination of the presence and amount of attrition. To estimate the amount of operations and maintenance (O&M) expenses for the rate year, the Company proposes that its adjusted test year level of O&M, less any expense categories that have separately been adjusted to test year levels, be increased by the forecasted annual growth rate in inflation of 1.98%, which equates to an absolute factor of 1.085. This results in an increase to O&M expenses of $9.575 million from the adjusted test year to the rate year. The growth rate is calculated from the DRI projection of the change in the chain-weighted Gross Domestic Product Price Index (GDPPI) from the mid-point of the test year (June 30, 1996) to the mid-point of the rate year (August 31, 2000), a period of 4.167 years. No party challenged either the use of the GDPPI as the proper measure of inflation or the use of the DRI-forecasted numbers. Therefore, we will accept the GDPPI growth rate for use in our attrition analysis.

The Company further asserts that two other factors that affect the rate year level of O&M expenses essentially offset each other, and thus, only an inflation factor should be used to estimate the Company's expenses in the rate period. Those factors are growth in the number of customers and some measure of productivity. The Company asserts that customer growth will result in an annual O&M increase of approximately $2.8 million, based on its sales forecast (which projects the number of customers by class in the rate year) and its marginal cost study (which estimates the additional cost per customer that the Company will incur). CMP proposes that instead of an explicit recognition of the additional costs, the Commission should effectively impute a productivity offset of equal magnitude.

In addition to the growth in costs related to new customers, CMP asserts that the restructuring of the electric industry will result in other increases in costs. The Company claims that retail access will require it to undertake new activities to meet its responsibilities to customers and energy suppliers. While the Company asserts that there will be real costs involved, it did not propose any explicit adjustment to account for those costs. Apparently, the Company believes that the inflation adjustment it proposes, combined with productivity improvements, will be sufficient to account for any increased costs resulting from retail access.

The OPA argues that the Company's projected growth in expenses overstates the level of expenses that CMP is likely to experience in the rate year. The OPA suggests that CMP has been able to essentially hold its O&M expenses flat between 1993 and 1996 due to several cost-savings programs and due to economies of scale. While the OPA acknowledges that including results for 1997 would tend to undermine his claim, he asserts that there has been no analysis to determine the normalcy of 1997 results. Also, because the Company's actual results do not reflect the impending sale of its generation assets, the OPA asserts that the resulting cuts in overhead expenses are not reflected either. Finally, the OPA argues that CMP has reduced its headcount between 1993 and 1997 by over 21%, and the Company has plans to further eliminate about 18 position after divestiture. For all these reasons, OPA believes that the Company should be able to hold its O&M expense level constant into the rate year and no attrition adjustment for these expenses should be included.

2. Analysis and Conclusion

In the Bench Analysis, the Advisory Staff agreed with the Company's proposal to increase the level of O&M expenses by the rate of inflation, but also proposed that a 1% annual productivity offset be applied to the growth rate to reflect projected cost savings. We agree that the Company's O&M expenses should be projected to grow at the inflation rate from the test year to the rate year. We do not accept the OPA's argument that the Company should be expected to hold its expense level nominally flat during the three-plus-year period from the test year to the rate year. In addition, while we will not (and indeed cannot, based on the record) make an explicit adjustment for additional activities that CMP may be required to undertake in the retail access environment, we acknowledge the possibility that there may be unavoidable and unforeseen expense increases related to the Company's role as an "intermediary" between power sellers and end-use customers.

Because we have accepted the potential for cost increases due to inflation and new business requirements, we will also include a factor to recognize the Company's ongoing responsibility to contain its costs. Thus, we include a 1% annual productivity offset in our attrition analysis. The 1% offset was chosen for several reasons. First, it is the amount included in the CMP ARP Stipulation approved by the Commission in Docket No. 92-345. It is also close to the 1.2% offset found appropriate by the Commission in Bangor Hydro-Electric's most recent rate case, Docket No. 97-116. Finally, 1% is approximately equal to the productivity savings projected to occur through the year 2000 by CMP in its own studies.

The Bench Analysis did not include any recognition of incremental customer costs in the rate year, because the Company recovers these costs through revenues from the new customers, and because the Company's embedded costs far exceed its marginal costs. Using the sales forecast developed by the Company, the Bench Analysis did recognize the additional revenues from new customers, but it did not include any recognition of the additional costs involved in adding new customers. To maintain parity in the recognition of both the additional costs and revenues projected for the rate year, we will include an increased expense amount for new customers based on the Company's marginal cost analysis. We will not, however, accept the Company's entire marginal cost calculation for our analysis. Because the amount of energy projected to be sold by CMP to its core customer classes in the rate year actually declines, and the total growth in MWh sales increases by only 3.1%, we do not believe any increase in demand-related distribution costs should be included in the marginal cost per customer to be used in our rate year growth analysis. Therefore, we will not include any distribution demand marginal costs (as shown on Exhibit Dumais/Cornwall 24, page 2 of 2), and we will only recognize the growth in customer-related costs when determining the O&M expense amount for rate year analysis. To be clear, the costs being eliminated are those included in the block of the referenced exhibit entitled, "Demand Costs (Rate per Customer)"; e.g., the "Total Demand per Customer" shown for the Residential-A rate class is $18.43. Our modification results in an expense increase due to additional customers of $2.223 million in the rate year.

In summary, for our attrition analysis, we increase CMP's test year O&M expenses that are not otherwise projected to rate year levels by the Company's forecasted growth in inflation less a 1% annually productivity offset. This results in an annual compound growth rate of .98% and an absolute growth factor of 1.0415 for the 4.1667 years from the test year to the rate year. In addition, we will increase the Company's rate year O&M expense level by $2.223 million to account for incremental non-demand-related costs due to the growth in the number of customers.[9] Finally, we will add back those expenses that have been specifically projected to remain at the adjusted test year levels. The exact amount of rate year O&M depends on the test year allowed O&M expenses which will be calculated in Phase II according to the principles articulated in Section III, above.

B. Other Rate Year Items

No party has contested the Company's method for determining the rate year level for the following items: rate base (gross operating property less accumulated depreciation); depreciation expense; income taxes (subject to adjustment for projected expense amounts); regulatory assessments; other revenue and expense; accumulated deferred income taxes; and other rate base and working capital requirements (subject to adjustment for projected expense levels). We have examined the Company's proposed rate year amounts for these items and find them reasonable. Therefore, we will accept these amounts subject to any adjustment necessary to conform the amount to the expense adjustment found reasonable for either the test year or rate year revenue requirements calculation, as appropriate.

C. Property Taxes

The Company proposed that the rate year level of property taxes be adjusted to recognize the historic relationship between plant in service and the taxes paid to the various municipalities. CMP asserts that historically, the mill rates imposed by municipalities have grown so that an annual growth factor of .7% per $1 increase in gross property should be used to project the Company's property taxes into the rate year. This results in an increase of $1.937 million in state and municipal taxes from the test year to the rate year.

The OPA opposes the inclusion of a growth factor in the calculation of rate year property taxes, based on an examination of the ratio of CMP's property tax expense to gross plant in service over the 1995 to 1997 period. The Company argues that the time period chosen by the OPA is too short to be meaningful and that an examination of recent 5-year and 10-years trends confirms its projected increase. The

[9] As noted previously, the sales forecast which we will ultimately rely on to set rates will account for the revenues associated with such new customers.

Company also claims the OPA is inconsistent in his use of 1997 data, since the OPA recommends excluding 1997 results from the expense growth rate calculation, but including it for his property tax analysis.

We believe the Company has presented a reasonable empirical basis for concluding that municipal property taxes will grow due to projected increases in the mill rate applied to the gross property value. However, the 10-, 7-, and 5-year trends indicate a decreasing rate of growth, and therefore, we will adopt an annual mill growth rate of .61%, which equals the most recent 5-year trend shown by the Company.

D. Sales Forecast

The Company's forecast of sales by major customer class was presented in the direct testimony of John Davulis. The sales forecast was later updated to include more recent information for several of CMP's largest customers. The forecast results, which project a decline in sales from 9,354 million kWh (1997) to 8,270 million kWh (2000), were used by the Company in its attrition study. The Company recognizes the need to again update its sales forecast during Phase II. In light of the update and the additional data to be supplied, we reach no conclusion concerning the accuracy of the forecasts presented here.

The Bench Analysis raised six issues related to CMP's forecast of sales to residential, commercial, paper industry, and "other" industrial customers. To put these issues in context, a summary of the Company's sales forecasting methodology is presented below.

1. Overview

CMP separately projected sales to the residential sector, the commercial sector, paper industry customers, and "other industrial" customers. It used a variety of techniques depending on the sector in question.

Residential Sales -- CMP relied on an end-use approach in which sales were determined for each of 25 usage categories, including a residual "miscellaneous" category. Appliance saturations were developed from recent survey data. The forecasted number of appliances were developed by multiplying the saturation data by projections of the number of residential customers. Residential customers were forecasted econometrically based on housing start projections for Maine and the historical number of residential customers. Usage per appliance type was estimated by multiplying the number of appliances by appliance-specific energy consumption coefficients. Projections were modified to reflect anticipated impacts of demand-side management savings and fuel switching.

Commercial Sales -- To forecast commercial sales, CMP used a combination of interviews with large commercial customers and projections of commercial output prepared by DRI. For each of 23 commercial segments, interviews were relied upon for the large customers. For the remaining customers in the segment, the DRI output projections in percentage terms were used to grow base year sales to the segment. The forecast was then adjusted to reflect the impacts of CMP's marketing programs and energy efficiency programs.

Industrial Sales -- Industrial sales to paper industry customers were based on customer interviews and contractual arrangements with the mills. Sales to other industrial customers were based on a combination of customer interviews and industrial output projections prepared by DRI. For the customers not interviewed, projected increases in industrial output by Standard Industrial Classification (SIC) code were multiplied by coefficients relating changes in output to changes in electricity consumption. The sales projections were then adjusted for the expected results of CMP marketing efforts and energy savings programs.

2. Load Forecasting Issues

The Bench Analysis identified six issues related to the Company's sales forecast. Each is addressed below.

a. Documentation

The Bench Analysis recommended that in Phase II, the 1999 sales forecast update be accompanied by a more detailed explanation of how the forecast was conducted. Mr. Davulis noted in surrebuttal testimony that the Company responded to approximately 140 data requests related to the sales forecast. The Company stated in its brief that it is willing to provide additional documentation and requests guidance on what CMP should provide.

The fact that 140 data requests were required to obtain the information needed to assess the Company's sales forecast strongly points to the desirability of additional documentation submitted with the Company's 1999 update. Without identifying specific items of information and data to be provided, the Company's 1999 update should be sufficiently detailed to accommodate the necessary review, with augmentation and clarification obtained through the discovery process. At a minimum, the update should provide the data relied upon, along with a description of how those data were developed. Any econometric equations (e.g., forecasted residential customers) should be provided accompanied by the historical data on which the equations rely and the forecasting assumptions on which the econometric projections are based. In short, a reviewer should be able to replicate the Company's forecast based on the Company's 1999 update and at least fundamentally understand how the underlying data were developed and used. Provision of such detail is seen to place no additional burden on the Company since such documentation and data would ultimately need to be provided in response to data requests.

b. Energy Usage per Appliance

The Bench Analysis noted that the appliance-specific energy consumption coefficients relied upon by CMP to develop its residential sales forecast tend to be lower than those used by other New England utilities. The importance of this issue varies across appliance type in proportion to the saturation of the appliance and the annual energy usage per appliance of a given type. For appliances that few customers own, or for appliances having low average annual usage characteristics, this issue is unimportant. For high saturation and high average energy consumption appliances, however, the issue is important.

CMP employed end-use metering to develop the usage coefficients. The current absence of end-use metering equipment in the field precludes augmentation of the original CMP samples or direct verification of CMP's coefficient estimates. CMP should, however, review available end-use estimates by appliance type to reconcile its own estimates with those relied upon by others. Such reconciliation is only meaningful for appliances with relatively high saturation and/or high energy usage. Consequently, CMP may restrict this reconciliation to appliance types accounting for more than 10 percent of non-miscellaneous residential energy consumption.

c. Income Elasticity

The average appliance usage estimates are adjusted by CMP to account for changes in usage resulting from changes in real per capita income. To accomplish this, the Company assumes that a given percentage change in real income will result in an equal percentage change in the usage coefficient. This assumption implies an income elasticity of demand equal to unity. While such an adjustment may be reasonable, CMP should conduct additional research to provide support for the unit elasticity assumption or, if warranted, refine the income elasticity estimate.

d. Fuel Switching

The Bench Analysis recommended that the Company's fuel switching and marketing impact assumptions be verified prior to completion of its 1999 update. This recommendation is consistent with existing Company plans to refine and verify its fuel switching and customer retention assumptions, and we agree that this information be included as part of the Phase II filing.

e. Reliance on Customer Interviews

The fundamental issue concerning the Company's methodology used to forecast sales to commercial and industrial customers relates to the combined use of customer interviews and business sector output projections developed by DRI. The Company contends that reliance on customer-specific information, where available, should be used to project loads and, where such information is unavailable, business sector output should be used to project energy sales. Customer-specific information is obtained through interviews with the larger customers within a specific business segment.

The Bench Analysis found two problems with the Company's approach. First, documentation of the customer interviews suggests that in many cases the customers interviewed have not rigorously addressed their own future energy consumption needs. Where substantial uncertainty is expressed by the customer, "no load growth" tends to be assumed by the Company, which may downwardly bias the interview-based projections.

Second, the projections prepared by DRI are for the business segment as a whole rather than for the portion of the business segment subject to customer interview by the Company. Consequently, the Bench Analysis raised questions regarding the applicability of the DRI projections.

To address these two concerns, the Bench Analysis recommended an alternative forecasting approach be used, such as an econometric approach. The Company indicates that it routinely prepares an econometric forecast along with its segment-based forecast as a reasonableness check. The Company has agreed to submit the econometric forecast in addition to the segment-based forecast in its 1999 update if the Commission desires it. Therefore, an econometric forecast for the commercial and "other" industrial classes should be made available as part of the Company's 1999 update.

The Company should also restrict its use of customer-specific information related to projections of sales for these segments to large changes not contemplated or accounted for in the DRI projections. The concern raised in the Bench Analysis regarding inappropriate application of the DRI business sector projections is valid, though customer-specific information regarding significant changes, such as customers ceasing operations or conducting significant expansions, may not be reflected in the DRI projections. It is, therefore, appropriate that significant deviations from the DRI projections applicable to specific customers be recognized by the Company's forecast.

f. Verification of Industry Projections

The Company should verify its paper industry sales projections, as recommended in the Bench Analysis and as CMP plans to do as part of its 1999 update.

V. DISCOUNT PRICING AND REVENUE DELTA

A. Description of Issue

CMP projects that in the rate year approximately 20% of its kWh sales will be made pursuant to discount, or non-core, prices. These non-core sales include numerous customer-specific special contracts as well as tariff-based programs targeted at particular groups of customers or end uses. Most of these contracts and programs were established during CMP's ARP for the express purpose of retaining or increasing sales. Some of CMP's projected rate year non-core sales reflect existing contracts with terms that extend past March 1, 2000; others reflect assumptions CMP has made about the need to renew or continue arrangements that could otherwise terminate. The "revenue delta" is the difference between the annual revenue CMP projects it will collect from non-core sales and the revenue those same sales would yield at core prices. As reported in its most recent ARP annual review filing (Docket No. 98-221), CMP's current revenue delta is $65 million.

The related issues for this proceeding involve the reasonableness of any discount CMP is contractually committed to provide in the rate year; the level of new discounts or renewals to assume or allow CMP to provide; the treatment of the revenue delta in setting CMP's revenue requirement; and the protocols that should be established for CMP to exercise pricing flexibility pending the establishment of a successor ARP.

B. Positions Before the Commission

In its direct brief, CMP explains the economic rationale for offering price discounts and describes the circumstances that led to the pricing flexibility it currently has under the ARP. The ARP provides CMP broad discretion to offer discounts to whomever it chooses within certain parameters (e.g., price floors). CMP states that it agreed to this component of the ARP to stop the "death spiral" it might otherwise experience from continual loss of load and price increases. CMP also explains that its agreement to bear the cost of discounts was a quid pro quo for retaining cost savings it achieved during the ARP.

CMP proposes to treat the discounts as follows. First, the Company's overall revenue requirement would be determined. Expected revenues from non-core sales would then be subtracted from the overall revenue requirement, and the remaining amount set as the allowed revenue to be collected from core sales. CMP projects revenues from non-core sales based largely on existing discount prices and arrangements, with some adjustments for known and expected changes. CMP argues that the Commission need not review individual contracts and programs because its incentives under the ARP provide sufficient assurance of the reasonableness of its price discounting. CMP also notes the availability of other approaches the Commission could use to assess the discounts short of case-by-case review, including a review of CMP's general pricing policies and practices, after-the-fact prudence reviews and spot reviews of selected contracts and programs. Finally, CMP argues strenuously against having to absorb any portion of the revenue delta, stating that such an outcome would be illegal and unfair.

The IECG defines the revenue delta as an amount of money CMP has voluntarily foregone to retain or increase sales. The IECG notes that CMP management argued that it be allowed significant discretion over its pricing. According to the IECG, CMP received this discretion under the ARP in exchange for relinquishing, to some extent, its ability to recover the amount of these discounts from other customers. The IECG further asserts that CMP's agreement to the ARP reflects its acceptance of the basic ARP structure as a long-run proposition. The IECG proposes that the Commission reduce CMP's revenue requirement by an amount equivalent to the revenue delta existing under the ARP. The IECG argues that such a reduction is consistent with 35-A M.R.S.A. § 3208(5) and (7) and the regulatory bargain the IECG asserts that CMP accepted with the ARP.

The OPA argues that price discounts given under the ARP are irrelevant to rates set in this proceeding because CMP must revamp all of its special contracts and programs to reflect the restructured electricity industry that will exist after March 1, 2000. The OPA urges the Commission to accept the process suggested by its witness, Scott Rubin, wherein competitive electricity suppliers would first compete for customers, after which CMP could consider the need to offer discounts on T&D service. The OPA proposes that the Commission consider the results of this process during 1999.

C. Analysis and Conclusion

We generally agree with CMP's characterization of this issue, as well as its proposed solution. As described by CMP, this is a rate case in which the Commission must: (1) determine CMP's revenue requirement; and (2) authorize rates that allow the Company to collect that revenue, given the assumptions about expected costs and sales. Although a future proceeding may result in a rate plan to succeed the current ARP, until then CMP’s rates will be based on traditional cost-of-service ratemaking once the current ARP expires. As such, in this proceeding, we must establish rates that give CMP a reasonable opportunity to earn a fair rate of return.

The IECG's position, if adopted, would extend the existing ARP. Doing so would conveniently continue the matching of pricing flexibility discretion with cost responsibility. However, there are several problems with the IECG's proposal. First, the IECG proposes an extension of the ARP in this one respect only (i.e., lost revenue from discounts), while using traditional ratemaking standards to reflect all other costs and savings (e.g., QF restructurings) that may have resulted from the ARP mechanism. This one-sided extension of the ARP is incorrect and unfair. Moreover, if the IECG's legal analysis is correct that the ARP defines the stranded cost recoverability standard required by 35-A M.R.S.A. § 3208(5)[10], it is not clear how disallowing the revenue delta, while determining all other ratemaking issues with traditional methods, would meet this standard.

Second, the IECG's proposal suggests that CMP's current ARP has an indefinite term, and that rebasing after 1999 was not contemplated. The plain language of the ARP Stipulation belies that conclusion. For instance, Paragraph 23 of the Stipulation requires an investigation in 1999 to specifically address whether, and under what terms, the ARP should continue or terminate. Attachment F, Section V.C. explicitly provides for Commission consideration of the appropriate treatment of any rates that diverge from the cap. *Detailed Opinion and Subsidiary Findings,* Docket No. 92-345(II)(Jan. 10, 1995).

Finally, the IECG's proposal could create undesirable incentives. Defining a price discount as revenue CMP must permanently forego could make CMP lose enthusiasm to pursue special pricing arrangements even when doing so would benefit CMP's ratepayers, stockholders and the State as a whole.

For these reasons, we reject the IECG's position that CMP's revenue requirement should be reduced by the amount of the existing revenue delta.

We next address how price discounts will be reflected in establishing CMP's March, 2000 rates. To set core T&D rates, we will adopt CMP's basic approach of reflecting a level of non-core sales and electric revenue in the rate year based on pre-March 2000 levels. This approach should reasonably reflect appropriate levels of sales and revenue at non-core prices because it mirrors pricing under the ARP in which CMP had the proper incentives to maximize its revenue. We will rely on ARP levels of non-core sales because an administrative review of CMP's discount contracts and

[10]Section 3208(5) states that utilities shall have an opportunity to recover stranded costs "comparable" to that existing before retail access. We interpret this section as a general legislative directive not to increase or decrease the certainty of cost recovery than that which would occur under established ratemaking principles. The section was not intended to require that utilities have no reasonable opportunity to recover their costs due to the existence of a prior pricing flexibility plan. Our view is that, in the absence of restructuring, we would have "re-based" CMP's rates to allow for a reasonable opportunity to recover its costs and would not have automatically disallowed the revenue delta.

targeted tariffs would be burdensome and, in some cases, inconclusive because of the customer-specific information needed to assess the reasonableness of any discount. In addition, administrative review would be further complicated by the uncertainty surrounding the emerging electricity markets. Finally, we expect to conduct an in depth review of CMP's T&D rates within two years of March 1, 2000. By then, there will be experience with T&D-only utilities and retail supply markets. In that proceeding, we will refine CMP's revenue requirement and rate design, and consider a multi-year rate plan. We are also likely to examine CMP's discount rates to determine their reasonableness and prudence for ratemaking purposes.[11]

In this case, we will determine the revenue responsibility of CMP's core customers by subtracting expected non-core T&D revenue from the overall revenue requirement we establish in this proceeding, and setting the remainder as the revenue attributed to core sales. As stated above, we will establish rate year non-core revenues based on pre-March 2000 levels; we will, however, allow adjustments for known changes. Implicit in this approach is an assumption that the total electricity prices associated with these non-core sales do not change, and their T&D contribution will be set by these total electricity prices less an estimate of market prices for the generation component. We will determine the amount of non-core T&D revenue for the rate year in Phase II.

Notwithstanding amounts reflected for March 1, 2000 ratemaking purposes, we expect CMP to continue to minimize any discount to T&D rates whenever it has opportunity to do so. Many of CMP's discounts are provided pursuant to contracts that expire prior to March 1, 2000; we expect that CMP will ensure that future contracting or contract renewals will give only discounts that are needed. Regardless of assumptions for ratemaking purposes, it would not be reasonable for CMP to simply replicate all of its existing discounts without considering changing conditions, and we assume it would not do so. CMP should re-assess the need for and magnitude of any discount it considers offering for T&D service in light of then-current conditions.[12]

We note that CMP has contractual obligations that extend beyond March 1, 2000 under existing contracts for bundled service which, after retail access, CMP cannot provide. Such contracts reflect a significant number of the arrangements that will continue in the rate year. Because CMP can no longer provide bundled service, these contracts must be restructured. CMP should do so in a way that seeks to preserve the benefit of the bargain to the contracting parties. This means, that the intent is for the customer's total rate for electricity to be unaffected. Thus, the customer's future market prices may have to be estimated to determine the proper T&D

[11]This may occur through spot audits of a limited number of contracts and tariffs.

[12]This is consistent with the general ratemaking process. For example, a utility should not spend the amount built into rates for tree trimming, if it is not necessary or reasonable to do.

prices to be charged. We direct CMP, in its Phase II filing, to provide us with a list of all bundled contracts that extend beyond March 1, 2000 and a discussion of CMP's efforts and plans to restructure those contracts.[13]

Finally, we address how new (or renegotiated) contracts and discounted tariffs should be reviewed pending the adoption of a new rate plan for CMP. For this purpose, we adopt a mechanism similar to that contained in the ARP. We direct that, for any proposed contract or tariff reflecting a discount from core rates, CMP must file the proposed contract or tariff with the Commission for a summary review. Each filing must include the following material:

- the customer's best market price for electricity supply; either actual or a well-supported estimate;

- specific and current information regarding the feasibility and cost of the customer's alternative to purchasing from CMP; and

- a demonstration that the contract or tariff complies with the provisions of the ARP relating to flexible pricing that would have been applicable.

We will review this material within 30 days of its filing. If, based on this review, we find the proposed contract or tariff complies with the applicable ARP pricing flexibility criteria, includes sufficiently reliable documentation of the customer's alternative and the customer's market electricity supply price, and reflects an electricity supply price that comports with our own information about prevailing market conditions, we will allow the contract or tariff to take effect. We contemplate that this review will be similar to that which now occurs under the ARP and that, if warranted, we will suspend the effectiveness of a contract or tariff pending further review (as may occur under the ARP).[14]

The 30-day review will not be an in-depth examination of the reasonableness of any contract or tariff, and, therefore, no prudence finding will be made. As mentioned above, we may review contracts and tariffs in a future proceeding to determine their prudence for ratemaking purposes. Upon a demonstration of good cause, CMP may request that a discount contract or tariff receive prior prudence review. Parties should assume that if the Commission conducts such a review, it may

[13]CMP should also identify and describe in its Phase II filing those contracts that obligate CMP to provide discounted T&D rates in the rate year that neither expire nor require a restructuring.

[14]In Phase II, we will refine the applicability of the existing pricing flexibility criteria to these contracts and tariffs.

take up to four months, the time period specified in the current ARP for pre-approval reviews.[15]

VI. COST OF CAPITAL

A. Overview

The Company seeks the opportunity to earn an overall weighted average cost of capital (WACC) of 9.789% on its rate base. Company witness David Brooks recommends that CMP's capital structure include a 55% common equity component and that the return on common equity be set at 12.00%, a figure which includes a 45 basis point (0.45%) upward adjustment for the combined effects of direct flotation costs (27 basis points) and market pressure (18 basis points).

Public Advocate witness Stephen Hill initially recommended an overall WACC of 8.56% on rate base in both his Direct and Surrebuttal Testimony. However, in its Reply Brief, the OPA recommends that 8.449% be used instead. Mr. Hill's original recommendation included a capital structure containing a 45% common equity component and a 10.00% "all-in" return on common equity. The 10.00% figure consisted of a 9.75% "core" cost of common equity plus a 25 basis point increment for flotation costs. In its Brief, the OPA recommends that the Commission abandon its long standing practice of allowing a flotation cost adjustment and simply use Mr. Hill's recommended 9.75% core cost of common equity.

In the Bench Analysis, the Advisory Staff, preliminarily recommended that the appropriate WACC for the Company was 8.44% based on a 45% common equity component and a cost of common equity of 10.00%, inclusive of a 15 basis point allowance for flotation costs. In a subsequent filing dated June 30, 1998 amending the Bench Analysis, the Advisory Staff corrected a mathematical error pertaining to the cost of equity and stated that its preliminary WACC should be raised to 8.50%, based on a 10.15% cost of common equity, which was the sum of a 10.00% core cost of common equity and a 15 basis point adjustment for flotation costs.

For the reasons set forth below, we find that the appropriate WACC for CMP's T&D-utility is 8.68%. This is based on 10.50% cost of common equity, which includes a 15 basis point (0.15%) adjustment for flotation costs, and a 47% common equity ratio.

[15] Commission review may take longer than four months if CMP files several major contracts at the same time.

B. Background on Cost of Capital

One of the steps in determining the Company's overall revenue requirement is the setting of a rate of return (ROR) that is applied to the Company's total rate base. While the allowed rate of return is generally referred to as the cost of capital, there is a distinction between the two concepts. Strictly speaking, the cost of capital is equal to the WACC, which is equal to the sum of the costs of the components of the Company's capital structure after each component is weighted by its respective proportion to the utility's total capitalization.

Judgment needs to be applied in arriving at the cost for each of the components of the capital structure. In particular, judgment is required to develop a forward-looking estimate of the cost of common equity. Our analysis of the cost of capital, especially with respect to the cost of common equity, sometimes implies a degree of precision that is not really present. Nevertheless, we must set an exact cost rate for each of the components and for the overall cost of capital to the utility.

The allowed rate of return which is ultimately applied to the rate base may contain adjustments to the cost of capital that reflect management efficiency or other considerations related to the balancing of ratepayer and utility interests. The overall rate of return must strike a balance between the interests of ratepayers, who are entitled to the lowest reasonable cost of service, and the utility, which is entitled to a rate of return that allows it to attract capital at a reasonable cost.

This relationship between the cost of capital and the utility's fair rate of return has been established by several familiar United States Supreme Court decisions. *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 282 U.S. 679 (1923); *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944); and *Permian Basin Area Rate Case*, 390 U.S. 747 (1968). The *Hope* and *Bluefield* cases establish the general principles that the return to common equity owners should be commensurate with the returns on other investments having corresponding risks and should be sufficient to ensure confidence in the financial integrity of the enterprise in order to maintain its credit quality and its ability to attract capital. In *Permian Basin*, the Court tempered the strict reliance on the returns paid to investors with the acknowledgement that commissions must consider the "broad public interest" when making decisions on the utility's rate of return. *Id.* at 791.

The Maine Law Court has also required that the Commission consider the interests of ratepayers when setting the rate of return. For example, in *New England Telephone and Telegraph Company v. Public Utilities Commission*, 390 A.2d 8, 30-31 (Me. 1978), the Law Court held that ratepayers' interests must be given substantial weight in the final determination of a utility's allowed rate of return. In prior cases, we also have made cost-of-equity adjustments to account for utility inefficiency. We have generally used such adjustments when the effect of the inefficient behavior results from inaction rather than action. *See* e.g., *Bangor Hydro-Electric Company, Proposed Increase in Rates,* Docket No. 86-242, Order at 17-50 (Me. P.U.C., Dec. 22, 1987) (25 basis point reduction on equity because of management inefficiency in the credit and collection and conservation and demand-side management areas).

In this case, we have been presented with no evidence that would lead us to adjust the cost of capital for any of these concerns. Thus, we can and will use the terms "cost of capital" and "rate of return" interchangeably.

C. Cost of Equity

1. Positions Before the Commission

a. David Brooks Analysis

Mr. Brooks, a witness for the Company, made a final “all-in” recommendation of a 12.00% cost of equity for CMP based on his subjective weighting of four estimates: (1) a 14.50% to 19.00% estimate based on a Comparable Earnings approach; (2) an 11.50% estimate based on a Two-Stage Discounted Cash Flow (DCF) analysis on a sample group of “A-rated” energy utility companies; (3) a 12.00% estimate based on the average of two Capital Asset Pricing Model (CAPM) analyses (one traditional CAPM and one “Zero-Beta” CAPM) applied to the same group of “A-rated” energy utilities/companies; and (4) an 11.20% estimate based on a Historical Stock-Bond Risk Premium model. Mr. Brooks then made a flotation cost adjustment of 45 basis points (included in his 12.00% recommendation) comprising a 27 basis point adjustment for direct issuance costs and 18 basis points for “market pressure.” In his Direct Testimony, Mr. Brooks gave each of his methodologies roughly equal weighting. However, in his Rebuttal Testimony, his final recommendation apparently relied more heavily on his Two-Stage DCF, CAPM and Historical Stock-Bond Risk Premium methodologies than on his Comparable Earnings analyses. These methodologies yielded an average cost of equity of 11.60%, including the aforementioned flotation cost adjustment. Mr. Brooks did not explain why (or by what magnitude) he reduced the weighting on his Comparable Earnings model or why he rounded the 11.60% indicated result in his Rebuttal Testimony upward to 12.00%.

b. Dr. Lawrence Kolbe Analysis

Dr. Kolbe, testifying on behalf of the Company, provided his own original research indicating that partial deregulation of a formerly fully regulated industry raises the risk profiles of all segments of the business in question. He presented this recommendation in support of the Company’s request for a 12.00% return on equity and a 55% common equity ratio in this proceeding. Dr. Kolbe’s findings were based on his examination of the partial deregulation of both the telecommunications and natural gas industries.

c. <u>Stephen Hill Analysis</u>

On behalf of the OPA, Mr. Hill recommended a 10.00% ROE for CMP primarily based upon the results he obtained using a traditional discounted cash flow (DCF) analysis on three separate sample groups of utilities. Mr. Hill examined a group of electric utilities, a group of natural gas distribution companies (Gas LDC's) and a group of water utilities and established a DCF cost of equity range of 9.22% to 10.27% (net of flotation costs). The midpoint of these estimates is approximately 9.75%, which was Mr. Hill's ultimate recommendation for CMP's core cost of equity (although Mr. Hill never explicitly stated that he relied on these results alone). Mr. Hill then added 25 basis points as a flotation cost adjustment based on Commission precedent in CMP's last fully litigated rate case, Docket No. 92-345 (Phase I).

To corroborate his DCF findings, Mr. Hill employed three check methodologies, the "Modified Earnings Price Ratio" (MEPR), a "Market-to-Book Ratio Analysis" (MTB) and a Capital Asset Pricing Model (CAPM). He applied each model to each of his three utility peer groups. The MEPR model produced a range of ROE estimates from 8.83% to 9.80% (with an indicated midpoint of 9.33%), while the MTB model yielded estimates between 8.63% to 10.06% (with an indicated midpoint of 9.44%). Finally, the CAPM indicated a range from 9.04% to 10.78% (with an indicated midpoint of 9.91%) before flotation costs. Regarding flotation costs, Mr. Hill stated that although he felt a flotation cost adjustment was unnecessary, he preferred not to relitigate the issue in this case and thus added 25 basis points based on the Commission's determination in CMP's last rate case, Docket No. 92-345 (Phase I). This resulted in Mr. Hill's "all-in" recommendation of 10.00%. In its Brief, the Public Advocate reiterated that there is no justification for the inclusion of a flotation cost adjustment at this time, thus resulting in a final OPA recommendation of a 9.75% return on equity for CMP.

d. <u>Advisory Staff Bench Analysis</u>

The Advisory Staff's Bench Analysis relied primarily on the quarterly version of the DCF Model applied to several utility peer groups to arrive at a cost of equity of 10.15% and a WACC of 8.44% for CMP. The Advisory Staff also employed the traditional annual version of the DCF model and a CAPM model as check methodologies.

The Bench Analysis examined four peer groups including two different (but in some cases overlapping) electric utility peer groups, a Gas LDC peer group, and a water utility peer group. The quarterly DCF model produced an ROE range of 9.36% to 10.90% (with an indicated midpoint of 10.13%) inclusive of 15 basis points for flotation costs. The annual DCF model results suggested a range 10-12 basis points lower at 9.24% to 10.81% (with an indicated midpoint of 10.03%), also inclusive of 15 basis points for flotation costs. The Advisory Staff's CAPM yielded ROE estimates from 9.84% to 13.41% (with an indicated midpoint of 11.63%). Advisory Staff, however, discounted these results and suggested that the water utility range alone (9.84% to 11.62% with an indicated midpoint of 10.73%) would be more indicative for a future "T&D-only" electric utility. Advisory Staff's recommendation of a 15 basis point flotation cost allowance was based on its survey of electric utility common stock issuances between 1994 and 1996, which was presented originally in Bangor Hydro-Electric's most recent rate case, Docket No. 97-116.

2. Comparable Sample Groups

a. Positions Before the Commission

Company witness David Brooks identified a single sample group of comparable companies for use in both his Two-Stage DCF analysis and his CAPM analyses. Mr. Brooks used all "energy utilities" listed in the September, 1997 Value Line database that met the following criteria: (1) an S&P bond rating of "A+", "A", or "A-"; (2) payment of a dividend on common stock; and, (3) a published consensus analyst's earnings forecast in the S&P *Earnings Guide.*[16] In his rebuttal testimony, Mr. Brooks identified the 46-company sample shown on Exhibit Brooks-16, which included electric utilities, gas & electric utilities and natural gas utilities, the majority of which were distribution companies.

Public Advocate witness Hill noted that Mr. Brooks's sample group included companies that were primarily natural gas pipeline/exploration companies, some of which had extremely high consensus growth rates that would cause his subsequent DCF results to be overstated. Mr. Brooks apparently fine-tuned his peer group between his direct and rebuttal filings; the size of his "A-rated energy utility" peer group declined from 57 companies in his direct testimony to 46 companies on rebuttal.

Mr. Hill constructed three different peer groups which he used throughout his analysis. His first peer group was composed of electric utilities from the *Value Line's* Standard Edition "Eastern Electrics" universe of companies that both: (1) were paying a common dividend, and (2) had an S&P bond rating of BBB or lower. *Value Line's* Standard Edition "Eastern Electrics" universe includes 34 of the 87 electric utilities *Value Line* follows, and 10 companies survived Mr. Hill's screening process. Mr. Hill's second peer group included natural gas LDCs that met the following criteria: (1) 90% or more of revenues must come from gas distribution; (2) must have an S&P bond rating of "A" or lower; (3) dividend payouts must not be in question; and, (4) other operations must not contribute more than 10% of corporate earnings. For his third and final peer group, Mr. Hill used the six water utilities followed in *Value Line's* Standard Edition.

[16]The S&P *Earnings Guide* began using I/B/E/S Earnings forecasts in January 1998.

The Company did not offer any specific criticisms of Mr. Hill's peer group selection process. The Staff's Bench Analysis offered two observations on Mr. Hill's peer group selection. First, regarding his electric utility sample, the Advisory Staff noted there was little justification in limiting the universe of electric utilities to only *Value Line's* "Eastern Electrics," thereby eliminating two-thirds of the industry from consideration. Second, Mr. Hill included two firms in his electric sample and one in his gas LDC sample that had announced mergers, thereby limiting the usefulness of their dividend yields and consensus growth rates.

The Bench Analysis constructed two electric utility peer groups, a gas LDC peer group and a water utility peer group which were used throughout its analysis. All companies in the peer groups had to: (1) be paying a common dividend; (2) have a published consensus long-term growth rate from I/B/E/S; and (3) not have announced merger plans prior to the point when Staff measured each company's share price for its DCF analyses.

The first peer group was a so-called "Cluster Analysis" electric peer group. The cluster analysis methodology seeks to minimize the geometric "distance" between the target company and its peers based on a number of risk measures. The Staff calculated six ratios, three meant to approximate business risk and three meant to determine financial risk and compared CMP against the *Value Line* (Standard Edition) universe over the 3-year period 1995, 1996 and 1997. The ratios used were: (1) Cash Flow per Share to Capital Expenditures per Share, (2) Electric Revenues as a Percent of Total Revenues, (3) Residential Electric Revenues as a Percent of Electric Revenues, (4) Pretax Interest Coverage, (5) Common Equity as a Percent of Total Capital, and (6) Operating Income as a Percent of Total Revenues. From the starting point of the 87 electric utility universe followed by *Value Line*, Staff selected the 19 most comparable companies to CMP based on natural breaks in its geometric distance calculations. After eliminating companies which were not paying a dividend, or for which there was no I/B/E/S long-term earnings estimate available or which had announced mergers, the Bench's Cluster Analysis peer group was narrowed to 14 companies.

The second electric utility peer group was selected based on bond ratings, similar to the screening methodology used by both Mr. Brooks and Mr. Hill. Advisory Staff identified 17 companies that were rated at or below the middle of the "Triple-B" range by either S&P or Moody's.[17] Based on the general criteria regarding dividend payments and the availability of consensus growth rates, discussed previously, five companies were deleted, leaving a "Bond Rating" electric utility peer group of 12 companies.

The third peer group comprised natural gas LDCs, which is consistent with the approaches used by Mr. Brooks and Mr. Hill. The Staff essentially adopted Mr. Hill's LDC peer group with modifications. First, due to the announced

[17]Baa2 or lower for Moody's, BBB or lower for S&P.

merger of Bay State Gas (BGC) with NIPSCO Industries, it removed BGC from consideration. Second, NUI Incorporated exhibited a long-term I/B/E/S growth rate (of 10.80%) that Staff characterized as "an obvious outlier" and therefore removed it from consideration. Finally, the Staff added South Jersey Industries (SJI) as the 10th company in the peer group based on SJI's meeting the bond rating criteria adopted by both Mr. Brooks and Mr. Hill.

The final peer group comprised water utilities. In addition to the Standard Edition *Value Line* companies, Staff added those Expanded Edition *Value Line* companies for which I/B/E/S earnings estimates were available and arrived at a 10-company sample that included all those companies included in Mr. Hill's 6-company water utility sample.

Neither the Company nor the Public Advocate offered specific comment on the Advisory Staff's selection criteria for peer companies.

b. Analysis and Conclusion

We believe that peer group analysis performs a very important role in setting the cost of capital, by eliminating or reducing the possibility of an anomalous result which can occur when analyzing just a single company. In this case, the restructuring of the utility industry, together with the mandated divestiture of CMP's generation assets, require us to consider the risk profiles of the other utility industries that remain largely regulated in order to determine where on the risk spectrum a regulated T&D-utility falls. As such, we agree in principle that currently integrated electric utilities and natural gas LDC's utilities should be considered in our analysis.

In general, we believe that an appropriate selection process should initially consider a large number of potential candidates for the peer group sample and the final selection should be based on systematic and objective criteria that properly identify companies that are most comparable to the subject company in terms of risk (and therefore in terms of required return).

By using the *Value Line* population of energy utilities as a starting point Company witness Brooks satisfies this concern. He also used the same general criteria regarding the payment of dividends and the availability of a consensus growth rate as did the Advisory Staff in its Bench Analysis. However, we find two critical flaws in the peer group Mr. Brooks identified in his Rebuttal Testimony. In Mr. Brooks's Rebuttal Exhibit 16, he includes 46 companies, 12 of which apparently were in the process of merging, that he later uses in his DCF and CAPM analyses.[18] We agree

[18]Mr. Brooks's yield calculations apparently were made in May 1998 while his consensus growth estimates were from June 1998. A survey of *Value Line* editions between December 1997 and May 1998, indicates that Allegheny Energy, American

with the Bench Analysis regarding the danger of including within any peer group companies that are in the process of being acquired by or acquiring another company. The inclusion within Mr. Brooks's peer group of such a large number of companies casts serious doubts upon any analyses based on that peer group.

The other flaw we see in Mr. Brooks's sample group is the inclusion of several companies that may not be comparable for reasons related to their lines of business. Mr. Hill noted that Mr. Brooks's sample group included gas companies "which are primarily pipeline/gas exploration operations. . ." and that the inclusion of such companies would overstate the cost of equity for CMP. We note that three companies used by Mr. Brooks, MCN Energy Group, Energen Corporation and UGI Corporation, have forecasted long-term consensus growth rates of 12%, 10% and 14% respectively, while no other company he used shows a rate greater than 7%. These outlying growth rates should have been a "red-flag" for Mr. Brooks indicating that further evaluation might be required.

While no party provided direct analysis of these three companies, their inclusion in the peer group can distort consensus growth rate estimates and, in turn, distort the results of a DCF analysis. Their inclusion, likewise, may produce suspect beta estimates that can bias a CAPM analysis. Indeed, the Bench Analysis eliminated a company (NUI Incorporated) from its natural gas LDC peer group simply because its consensus growth rate was an "obvious outlier" and would have unduly distorted the results of its DCF analyses on that peer group. We believe that the Bench Analysis conclusion regarding the issue of outlying data points is appropriate. The inclusion of these companies in Mr. Brooks's peer group raises serious doubts about the reliability of any subsequent analyses utilizing this peer groups data points.

Mr. Hill began his electric utility peer group selection by considering the 34 market-traded electric utilities in the eastern region of the U.S. that are followed by *Value Line*. In doing so, he failed to consider more than 53 utilities in the U.S., some of which may be closer in risk level to either the currently fully-integrated CMP or CMP's future T&D-utility than the companies he identified. Despite the fact that we would have preferred Mr. Hill to have utilized a larger starting population of electric utilities, we note that Mr. Hill's final recommendation did not appear to be biased one way or another as a result of this drawback.

As noted by Mr. Brooks and by the Advisory Staff, we are also concerned that DQE and LILCO were included in the Hill sample group, because both companies had announced mergers. Although DQE has since announced that it has terminated its merger with Allegheny Energy, the share price and growth rates

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Electric Power, Bay State Gas, Central & Southwest, ENOVA, Kansas City Power & Light, KeySpan Energy (now Marketspan Energy), Nevada Power, NIPSCO Industries, Orange & Rockland Utilities, Sierra Pacific Resources, and Western Resources were involved in mergers when Mr. Brooks collected his data.

used by Mr. Hill in a subsequent DCF, MEPR or MTB models were measured while the merger process was ongoing. Mr. Hill agreed with this criticism but noted that removing both companies from his analysis would not skew his results or change his final recommendation.

The “Cluster Analysis” peer group in the Bench Analysis provides a sound basis for identifying CMP’s cost of equity. We recognize that the use of historical financial and operating ratios for a 3-year period (1995-1997) is an imperfect method for identifying companies that are comparable in risk to CMP at the present time. Because the companies comprising the *Value Line* universe are fully integrated electric utilities as opposed to T&D-only utilities, the selection of a sample of peer group companies will necessarily be difficult and will require the exercise of sound judgment. Given the limitations and uncertainties of forecast data and the possibility that financial and operating ratios for a shorter time period may reflect short-term aberrations rather than fundamental changes in business and financial risk, we believe that a 3-year period properly balances these considerations. We also believe that both the cluster analysis methodology and the risk measures used in the Bench Analysis are appropriate.

While the cluster analysis did not explicitly include bond ratings as a risk measure, the measures of business and financial risk that were used include financial and operating ratios commonly employed by credit analysts (e.g., common equity ratio, pretax interest coverage and cash flow/capital expenditures ratio). The “Cluster Analysis” peer group indicates a range of S&P bond ratings from AA- (MEC) to BBB- (UIL) and a range of Moody’s ratings from A1 (NES) to Ba2 (TNP). Overall, it would appear that the “Cluster Analysis” sample group has an “average” S&P bond rating in the “Low Single-A / High Triple-B” range (or A-/BBB+ for S&P or A3/Baa1 for Moody’s). The “Bond Rating” electric peer group contained in the Bench Analysis shows slightly lower bond ratings than the Cluster Analysis group, with an S&P rating range from BB+ (PNM & FE) to BBB+ (PSD) and a Moody’s rating range from Ba1(PNM) to Baa1 (BSE & EUA). On average, it would appear that the Bond Rating electric peer group has an aggregate bond rating in the “Low Triple-B” range (BBB- for S&P or Baa3 for Moody’s).

We find that a peer group of gas LDCs may provide us useful information. There is undoubtedly some convergence occurring between the gas and electric industries as Mr. Brooks has pointed out on several occasions. Given our concerns about Mr. Brooks’s peer group in general, we will consider the gas LDC peer groups proposed by Mr. Hill (after removing Bay State Gas) and by the Advisory Staff in our final analysis. Staff’s gas LDC peer group appears to have an aggregate bond rating in the area of the “Mid to Low Single-A” range (A/A- for S&P, A2/A3 for Moody’s).

We are less certain that a peer group of water utilities provides valuable benchmark information in this proceeding. Water utilities are the last remaining “pure” monopoly utility available for our consideration at this time. In this regard they do bear a resemblance to our perception of the future regulated T&D utility. It would be premature, however, to conclude that water utilities have exactly the same risk profile as a transitioning electric T&D utility. At most, these companies provide a floor for our analysis of cost of equity. To the extent that we will consider the water utility peer group in this proceeding, we will use the water utility peer group in the Bench Analysis, because it is the larger of the two and it encompasses Mr. Hill’s peer group. This water utility peer group appears to have an aggregate bond rating in the “High to Mid Single-A” range (A+/A for S&P, A1/A2 for Moody’s).

We are satisfied that each peer group described above provides us some useful information (e.g. water utilities help determine a floor) that will allow us to determine an appropriate cost of equity for CMP. These peer groups are populated by companies that are either completely or primarily utilities, and they encompass what the parties consider to be the relevant range of risk profiles as determined by bond ratings. At one end of the spectrum is the “Bond Rating” electric utility peer group which carries a “Low Triple-B” risk level and at the other end are the water utilities at the “Mid to High Single-A” risk range.

3. Discounted Cash Flow Analyses

a. Positions Before the Commission

Company witness Brooks used a Two-Stage DCF model based on growth and yield statistics suggested by his “A-rated” energy utilities peer group. The average current (D_0/P_0) dividend yield appears to be calculated for the month of May 1998 while his average first stage consensus growth rate comes from I/B/E/S estimates from June 1998. Mr. Brooks estimates the second stage growth rate for these companies to be 6.0% based on his assumption that the industry beta for electric utilities will rise from the current level of 0.75 to 0.90. Mr. Brooks concluded that his DCF model yielded an estimated cost of equity of approximately 11.50% inclusive of his flotation cost adjustment of 45 basis points.

Public Advocate witness Hill used the standard annual DCF model to develop his DCF results. Mr. Hill used each company’s average stock price for the most recent 6-week period and annualized the current quarterly dividend (D_0) to calculate his yield. If a company had recently raised its stock dividend, he did not raise the current dividend by multiplying it by (1+g%) but rather used the current dividend (D_0) to calculate his DCF dividend yield. Mr. Hill examined several estimators to determine the dividend growth rates for his peer companies including the consensus I/B/E/S forecasts, *Value Line* forecasts, and *Value Line* historical data. He ultimately relied on his own calculated internal growth rates using the ”b times r plus s times v” method. To calculate the “b times r” segment of the growth rate, Mr. Hill relied on *Value Line* estimates of earnings retention rates (“b”) and return on equity (“r”). The “s times v” portion of his calculation also relies on *Value Line’s* forecast of the growth in the number of shares expected between 1998 and 2002. Mr. Hill determined that his calculated growth estimates did not differ materially from the forecasts published by I/B/E/S and *Value Line*. The DCF model employed by Mr. Hill indicated an average cost of equity of 9.22% for his electric utility peer group, 10.27% for his gas LDC peer group and 9.53% for his water utility peer group. Mr. Hill's final recommendation of 9.75% is roughly consistent with the middle of the DCF range indicated by his electric and gas LDC peer groups.

The Bench Analysis used a DCF analysis for the various peer groups to estimate the cost of equity of CMP and placed greater weight on the results produced by the quarterly version of the DCF model. The Staff's results suggest that the quarterly DCF cost of equity (including a 15 basis point flotation cost adjustment) ranges between 8.30% and 9.20% for the Cluster Analysis electric sample, 8.65% and 10.20% for the Bond Rating electric sample, 10.65% and 10.90% for the gas LDC sample, and 8.70% to 8.75% for the water utility sample. The annual DCF model produces estimates on the order of 10 to 12 basis points lower across the board. The preliminary DCF recommendation was 10.13% presented in the Bench Analysis, the midpoint of a range between 9.36% (top of the water utility group's DCF range) and 10.90% (midpoint of the gas LDC range).

No party disputed the inputs to the Advisory Staff's quarterly or annual DCF models. As explained in the Bench Analysis, the DCF model requires a current share price, a current dividend, and an expected growth rate. For all the sample groups, the Bench Analysis used a 20-day average of recent stock prices (May 22, 1998 to June 19, 1998), the current indicated dividend (from the June 1998 S&P *Stock Guide*) raised by a factor of (1+g%) to arrive at a forward looking dividend amount D_1, and the consensus 5-year earnings I/B/E/S growth rates for each company (from the June 1998 edition of the I/B/E/S Report).

b. Analysis and Conclusion

We find that the DCF analyses provided by the Advisory Staff and the OPA, both of which rely on "single stage" growth rate models, provide a reasonable basis for determining CMP's cost of common equity and we will rely primarily on these results in our final analysis. We decline to rely on the "Two-Stage" formulation of the DCF model used by Mr. Brooks. As he explains in testimony, published earnings growth rate forecasts (such as the consensus figures from I/B/E/S) are intended to apply only to the next five years. Investor's growth expectations beyond the next five years could be quite different and, therefore, the standard "constant growth" or single stage model could be misleading. Mr. Brooks estimates the post 5-year growth rate on his Exhibit 10 using a methodology developed by Brigham and Aberwald at the University of Florida. Mr. Brooks concludes that this post 5-year growth rate is 6.0%.

The issue here is not whether a Two-Stage DCF calculation is conceptually defensible, but rather whether the particular application of this methodology is sound. We find that Mr. Brooks's second stage growth rate analysis merely assumes a particular result and is, thus, unpersuasive. Specifically, it assumes that electric utilities become riskier after five years (the beta increases from 0.75 to 0.90 percent) and the average earned return on equity increases to 13.10%. He further assumes that stock issuances will be sufficient to add another 150 basis points to the growth rate. These assumptions are then combined to produce a 6.0% growth rate conclusion. However, what is lacking from Mr. Brooks's analysis is any evidence that the investment community actually holds these expectations of higher profitability. Obviously, different assumptions would have produced a different result. In rejecting this result, we do not mean to suggest that a Two-Stage model is not a legitimate application of the DCF, but its application must be based upon supportable evidence. In addition, if Mr. Brooks had presented a traditional single-stage DCF analysis using the peer group he identified in his Rebuttal Exhibit Brooks-16, we would be reluctant to give it much weight due to the concerns about the peer group we discussed previously.

In evaluating single stage models, we generally prefer to use forward-looking consensus growth rate estimates in a DCF analysis rather than those based on the opinion of a single analyst. When Mr. Hill relied on *Value Line* as the source to calculate his forward-looking "(b x r) + (s x v)" dividend growth rate, he was in fact using the opinion of a single analyst. Despite this weakness, we find Mr. Hill's calculated growth rates more than likely did not produce DCF results that would have differed markedly from the DCF results he might have obtained had he simply used the consensus I/B/E/S growth rates directly. The table below illustrates the alternative dividend growth rates considered by Mr. Hill.

Alternative Dividend Growth Rates

Peer Group	Avg. Used by Mr. Hill	Avg. I/B/E/S Consensus
Electric	3.98%	2.41%
Gas LDC	5.63%	5.66%
Water	5.34%	5.93%

Source: Hill Pref. Dir. Test. Exh. SGH-1, Schedule 4, pages 2, 4, and 6; Schedule 6, pages 1, 2, and 3.

There are two other areas of disagreement with respect to the DCF analyses proposed by Mr. Hill and by the Advisory Staff. Company witness Brooks makes the point that Mr. Hill did not properly increase the current common stock dividend (D_0) in his DCF model by his assumed growth rate (1+g%) to arrive at the required "next period dividend" (D_1), thereby understating the yield component of his DCF calculation. We agree that the appropriate dividend for use in the DCF model is the “next period dividend” (D_1). Based on the Advisory Staff’s Bench Analysis, it appears that this could lead to a 15 to 25 basis point understatement in an annual DCF analysis[19]. This of course assumes that Mr. Hill made this assumption across the board with every company in his sample group. Our examination of his calculations indicates that this was not the case.

The other area of disagreement involves the Advisory Staff’s stated preference for the quarterly DCF model in the Bench Analysis. The Public Advocate pointed out, among other things, that FERC in its December, 1986 Order No. 461 determined that the quarterly version of the DCF model is improper and unjustified. Despite FERC’s determination, we are not entirely convinced that investors would be overcompensated if we used a quarterly DCF model as a basis for our final determination. A fundamental premise of financial theory is that a dollar today is worth more than a dollar tomorrow. We believe that investors value a quarterly dividend more highly than an annual dividend, and to the extent an adjustment can be easily incorporated into the DCF model, we will consider it. We note that the evidence presented here indicates that the difference between the quarterly and annual DCF models is rather small, on the order of 10 to 12 basis points.

4. Capital Asset Pricing Model

a. Positions Before the Commission

Company witness Brooks used the average of two versions of the CAPM model, a “Traditional” CAPM and the so-called “Zero-Beta” CAPM, to arrive at his CAPM recommendation of 12.00% (inclusive of a 45 basis point adjustment for flotation costs). The “Zero-Beta” CAPM differs from the traditional model in that it assumes a flatter security market line (or risk/return trade-off). This has the effect of predicting higher returns for stocks with betas of less than 1.0 and lower returns for stocks with betas greater than 1.0 than the traditional CAPM. Both models employed a risk free rate (R_f) of 6.00% based on Treasury Bonds with a remaining maturity greater than 10 years. The equity market risk premium (R_p) of 7.40% used by Mr. Brooks was based on the historical Ibbotson & Sinquefield series covering the years 1926 through 1997. Mr. Brooks used a beta of 0.70 based on the sample group of 57 “A-rated” energy utilities shown on Exhibit Brooks-9 of his Direct Testimony.

Public Advocate witness Hill also used two versions of the CAPM model, primarily as a check methodology for his DCF results. Both of his CAPM models utilized a risk free rate of 5.00% based on 3-Month Treasury Bills and 3-Month Treasury Bill futures prices. Like Mr. Brooks, Mr. Hill based his equity market risk

[19]Per exhibits COC-13 & COC-15, the Cluster Analysis group average price is $34.758, average D_0 is $1.77, for an indicated yield of 5.09% versus the forward yield of 5.24%, a difference of 0.15%. Bond Rating average price is $33.375, average D_0 is $1.61, for an indicated yield of 4.81% versus the forward yield of 5.04%, a difference of 0.23%.

premium on the historical Ibbotson & Sinquefield series covering the years 1926 through 1997, except that his equity market risk premium was calculated against "Short-Term Government Bills" rather than "Long-Term Government Bonds." Mr. Hill added a twist, however, in that he used both the geometric and arithmetic mean risk premiums to calculate his final results. Mr. Hill's estimated beta coefficients are the *Value Line* averages for each of his peer groups, namely 0.65, 0.60 and 0.58 for the electric, gas LDC and water utilities respectively.

The Bench Analysis includes a CAPM analysis as a check methodology. Its model employed a risk-free rate of 5.67% based on the then current (June 19, 1998) 30-Year Treasury Bond. Unlike Mr. Brooks and Mr. Hill, the Bench Analysis did not use the Ibbotson & Sinquefield historical series to calculate the equity market risk premium. Rather, it performed a quarterly DCF analysis on the S&P 500 Index as of March 31, 1998, and arrived at an equity market risk premium of 8.93%. The beta estimates used were those of the individual companies included in its peer groups and ranged from 0.45 to 0.85.

b. Analysis and Conclusion

We find that the CAPM results provide a useful check on the DCF analysis, although not as reliable a check as in the past. The theoretical weaknesses of the CAPM highlighted in the Bench Analysis causes us to rely more heavily on the DCF analysis. The lack of a true forward-looking beta is a major obstacle given that a pure T&D-only utility industry does not exist at this time. The CAPM is familiar to us, and thus we need not discuss the basic structure of the model in this order.

We will not rely on Mr. Brooks's CAPM analyses for several reasons. First, we are not convinced that his beta estimate of 0.70 is reasonable, based on our belief that the future T&D-utility industry will be less risky than today's fully integrated electric utility industry. We will discuss our views on the relative riskiness of the T&D-utility industry in more detail later. Second, Mr. Brooks's risk-free rate of 6.00% is rather high based on recent market rates. Finally, we do not believe that the "Zero-Beta" CAPM is an appropriate estimating tool where one uses "adjusted" beta statistics. *Value Line's* published common stock betas are already adjusted for what is known as "mean reversion," which is the tendency of raw historically calculated betas to move towards the market beta of 1.0. The "Zero-Beta" CAPM makes a similar mathematical adjustment, by moving low-beta stock returns upward towards the return of a stock with a beta of 1.0, or towards the "market" return. In essence, the adjustment for "mean reversion" is double-counted when one uses the "Zero Beta" CAPM and an "adjusted" beta, such as those published by *Value Line* or *Merrill Lynch*.

With respect to Mr. Hill's CAPM models, we agree with the Company that it is improper to use a geometric mean in the CAPM model. We are also concerned that Mr. Hill's proxy for the risk-free rate (3-Month U.S. Treasury Bills) has a maturity that is much shorter than that of equity securities (which is theoretically infinite), and therefore, may not be appropriate for use as the risk-free rate in a CAPM analysis. However, the 3-Month Treasury Bill used by Mr. Hill in his analysis indicated a risk-free rate of 5.00%, which is closer to the recent yield levels on the 30-Year Treasury Bond than the other risk-free rates presented. Since Staff's CAPM analysis used a 5.67% risk-free rate and Mr. Brooks' CAPM analyses used a 6.00% risk-free rate, Mr. Hill's CAPM analysis is the only one that actually uses a risk-free rate that is "current" if Long-Term Treasury Bonds are considered to be most appropriate for use in the CAPM. In the past, we have considered both the 3-Month Treasury Bill and the 30-Year Treasury Bond in CAPM analyses. However, if we had to choose one or the other as our preferred CAPM risk-free rate, we would choose the 30-Year Treasury Bond due to the maturity issue we mentioned above. We also note that the Treasury yield curve is relatively flat at this time, meaning that our preference for the risk-free instrument is not critical in this analysis.

This leaves the potential problem that Mr. Hill's recommended arithmetic mean equity risk premium of 8.90% may not match the 30-Year Treasury Bond. In fact, Mr. Brooks showed that the appropriate historical equity risk premium for Long-Term Government Bonds was 7.40%. However, the DCF analysis on the S&P 500 included in the Bench Analysis indicated that a forward-looking equity market risk premium of 8.90% versus the 30-Year Treasury Bond was not outside a reasonable range in the current market environment. This is far from certain given recent volatility in the equity markets and the talk of lowered expectations for future earnings for U.S. corporations, but it is not an implausible result. Using Mr. Hill's beta range of 0.58 to 0.65, a 5.00% risk-free rate and an equity market risk premium range between 7.40% and 8.90% suggests the following CAPM cost of equity estimates (before flotation costs) :

Examiners Modified CAPM Results

		R_p	R_p	R_p
Beta (ß)	R_f	**7.40%**	**8.15%**	**8.90%**
0.58	5.00%	9.29%	9.73%	10.16%
0.63	5.00%	9.66%	10.13%	10.61%
0.65	5.00%	9.81%	10.30%	10.79%
Average		9.59%	10.05%	10.52%

Note: Standard CAPM Formula = R_f + ß x (R_p)

As a check methodology, the above table indicates a CAPM estimated cost of equity range of roughly 9.30% to 10.80% with a midpoint of 10.05% prior to any adjustment for flotation costs.

5. Other Models

a. Positions Before the Commission

Mr. Brooks also offered two Comparable Earnings analyses for our consideration. For his first Comparable Earnings analysis, Mr. Brooks used all the companies listed in the June, 1998 Standard & Poor's (S&P) *Earnings Guide* that met the following criteria: (1) a "B+" Common Stock Ranking; (2) a published consensus analysts' earnings forecast available for both 1997 and 1998, and (3) a positive book value of common equity. Mr. Brooks identified 483 companies that met all these criteria and determined that their average expected cost of equity was 19.00% (excluding flotation costs) for fiscal years 1998 and 1999.

For his second Comparable Earnings analysis, Mr. Brooks used all the companies listed in the September, 1997 *Value Line* that had a *Value Line* Safety Ranking of "3" and a tangible net book value of common equity of $1.00 per share or higher. Mr. Brooks identified 950 companies that met these criteria and determined that their average earned accounting return on equity was 14.50% (without flotation costs) over the 1992 to 1997 historical period.

Mr. Brooks also offered a Historical Stock-Bond Risk Premium analysis based on the returns of the Moody's 24 Electric Utilities Stock Index compared to Long-Term Treasury Bond rates from 1932 through 1996. The results indicated that an electric utility equity risk premium of 4.68% was appropriate, and he added this to his Long-Term Treasury Bond rate of 6.00% (at the time) to arrive at a cost of equity estimate of roughly 10.70% before flotation costs.

OPA witness Hill offered two alternative models that he considered to be strictly check methodologies. His so-called "Modified Earnings Price Ratio" (MEPR) model yielded cost of equity estimates between 8.83% to 9.80% before flotation costs. Mr. Hill's Market-to-Book Ratio (MTB) analysis showed similar results, with a range from 8.63% to 10.06%.

b. Analysis and Conclusion

Because Mr. Hill characterized his alternative methodologies as being strictly a check for his DCF and CAPM analyses, we will not discuss the merits or drawbacks of either his MEPR or MTB models. We will also not place any weight on them in our final determination.

Since Mr. Brooks relied heavily on his Comparable Earnings analyses and his Historical Stock-Bond Risk Premium analysis, we will discuss them briefly here. Both of Mr. Brooks's Comparable Earnings models have serious flaws. Mr. Brooks admitted on cross-examination that both models use screening criteria (S&P "Stock Rating" and Value Line's "Safety Ranking") that are apparently based heavily on the analysis of historical financial ratios.

Mr. Brooks's "forward looking" Comparable Earnings model produced an expected return on equity estimate of 19.0%. We have serious concerns about the true comparability of the sample group and, thus, its applicability to the utility industry, given that only 25 of 483 companies in the sample are electric utilities. In addition, as Mr. Hill noted, this model is inherently biased upward because Mr. Brooks compares future earnings per share estimates with book value per share amounts from a prior period. We do not believe these results are relevant to the analysis of the utility industry and will not consider this model in our final decision.

Mr. Brooks's second Comparable Earnings model, which yielded a return on equity estimate of 14.50%, is also flawed. Mr. Brooks assumes that the historical accounting return on equity results for these 950 firms from 1992 through 1997 are somehow related to market expectations of common stock returns for a T&D-utility today. He has not provided any evidence to support this claim. Even if such evidence concerning investor expectations were available and Mr. Brooks' sample group consisted of, for example, only the *Value Line* universe of electric utilities, we would remain highly skeptical of this methodology because many utilities have unregulated operations which affect the accounting return on equity of the parent company. If Mr. Brooks had in fact compiled these accounting returns from *Value Line*, the figures would have been those of the parent or holding companies and would thus have been "contaminated" by the operating results of any non-regulated business ventures or subsidiaries.

We also will place no weight on Mr. Brooks's Historical Stock-Bond Risk Premium analysis. The Public Advocate argued " that historical stock-bond premiums cannot reliably indicate investors' *current* (emphasis in original) expectations at a given time because the premium or difference is extremely volatile over time." We agree and believe that equity risk premiums vary over time depending on interest rates and economic conditions. Mr. Brooks did not provide persuasive arguments that the risk premium he measured was appropriate in today's markets. In fact, if we used Mr. Brooks's indicated risk premium of 4.68% in the current market where the 30-Year Treasury Bond is yielding roughly 5.00%, we would arrive at an estimated cost of equity of 9.68% for CMP before flotation costs.

6. Issuance Costs

a. Positions Before the Commission

Company witness Brooks proposed a 45 basis point (0.45%) flotation cost allowance comprising a 27 basis point increment for direct issuance costs and an additional 18 basis points allowance for so-called “market pressure effects.” The term “market pressure” refers to the cost to current shareholders that theoretically occurs when blocks of new shares are issued. Mr. Brooks submits that since 1946, CMP has incurred direct issuance costs equal to 4.5% of the face value of the securities issued, which accounts for the 27 basis points.

The Bench Analysis proposed that flotation costs be limited to a 3.0% increment for direct issuance costs and cited past Commission precedent denying a “market pressure” adjustment. The 3.0% increment for direct issuance costs was based on a market survey of direct common equity issuance costs in the electric utility industry. This incremental cost translated to roughly a 15 basis point (0.15%) upward adjustment in the Company’s core cost of common equity.

The Public Advocate argued against a flotation cost adjustment. According to the OPA, flotation costs should only be allowed when future stock issuances are likely to occur. He added that, if anything, CMP will most likely be buying back stock in the near future as opposed to issuing new stock. The Public Advocate, citing past Commission precedent, also urged us to reject the Company’s proposed market pressure adjustment.

b. Analysis and Conclusion

We will continue to allow a flotation cost adjustment at this time and adopt the Bench Analysis recommendation of a 3.0% or 15 basis point (0.15%) increment for direct issuance costs. We believe that forward-looking issuance costs, rather than historical costs as proposed by the Company, are most relevant for determining a flotation cost allowance, and the Bench Analysis included the most current data regarding the direct issuance costs of common equity. As with any expense item, CMP must minimize its equity issuance costs, and since this is a prospective adjustment, we will use forward-looking cost data to determine an appropriate amount. We acknowledge the OPA’s contentions that it is highly likely that CMP will buy back stock in the foreseeable future given its generation divestiture[20] and the fact that CMP has not issued common stock since 1990 but has been collecting a flotation cost allowance nevertheless. However, we recognize that the issuance of common stock (similar to debt instruments) is not accomplished without out-of-pocket costs and investors expect and should be compensated for them. Since we have not included a normalized (or amortized) expense reflecting these costs in CMP’s revenue

[20]This depends on the purchase price paid by the generation buyer, but as noted elsewhere, we assume that the FPL agreement will eventually close.

requirement, it is appropriate to include the adjustment in the cost of equity. We note that in the future, given CMP's current holding company structure, it will be difficult to allocate a normalized dollar amount between the utility and CMP's other subsidiaries, whereas including this cost as a percentage and including it in return on equity does not raise allocation issues.

As for the so-called "market-pressure" adjustment recommended by the Company, we have previously stated that we believe "market pressure" adjustments are speculative at best and that "statistical analyses of actual evidence are inconclusive." Docket No. 92-345 (Phase 1) Order at 34. We have not been presented with any evidence in this proceeding that would persuade us to change our opinion.

7. Cost of Common Equity

The cost of equity recommendations for CMP range from the Public Advocate's 9.75% to the Company's 12.00%. The Bench Analysis developed a cost of equity recommendation that included the elements of a traditional cost of equity analysis and recommended 10.15%, including a 15 basis point adjustment for flotation costs, based on a range of 9.36% to 10.95%. We conclude that the proper cost of equity for CMP's post-divestiture T&D-utility lies within the range indicated by the quarterly DCF analyses provided in the Bench Analysis. In the past, after determining what we considered to be a reasonable range for the cost of equity, we typically elected to use the midpoint of that range. However, we recognize that the electric utility industry is in a period of transition and that this carries a degree of added uncertainty, or risk, that should be factored into our decision. This leads us to depart from our occasional practice of choosing the midpoint of the "reasonable range" for the cost of equity.

Therefore, we adopt 10.35% as CMP's "core" cost of common equity and add 15 basis points (0.15%) for flotation costs for an "all-in" cost of common equity of 10.50%. This number represents roughly the 3rd quartile of Advisory Staff's reasonable quarterly DCF range of 9.36% to 10.90%[21], which is higher than the midpoint and median results for either of its electric utility peer groups, and closer to the median result of 10.65% indicated by its natural gas LDC group. We find additional support for a 10.50% cost of equity in OPA witness Hill's analysis. If we consider Mr. Hill's electric and gas LDC peer groups, add 15 basis points for flotation costs, and use his water utility peer group as a floor in a manner similar to that used in the Bench Analysis, his reasonable annual DCF range is roughly 10.05% (top of water utility range) to 10.70% (median of Mr. Hill's gas LDC peer group) with a midpoint of roughly 10.40%. The indicated 3rd quartile result for this range is 10.54%.[22] Though we are

[21] The average of the midpoint (10.13%) and high end of the range (10.90%) is the "3rd quartile point" of approximately 10.50%.

[22] The average of the midpoint (10.40%) and the top of the range (10.70%) is

reluctant to place great weight on any of the CAPM analyses, the CAPM results we calculated earlier suggest a cost of equity range of 9.30% to 10.80% with a midpoint of 10.05% before flotation costs (or 9.45% to 10.95% with 10.20% midpoint including 0.15% for flotation costs). Our final 10.50% recommendation is again in the area of the 3rd quartile point of our CAPM calculations.

We agree with the Bench Analysis and the Public Advocate that the risk profile of a regulated, pure T&D-utility lies within a range defined at the low end by water utilities and at the high end by existing integrated electric utilities or gas LDC utilities. We also believe that the risk profile of the T&D-utility will not increase in a post-divestiture environment as posited by Dr. Kolbe on behalf of the Company. Dr. Kolbe's analysis of deregulation activities in the telecommunications and natural gas industries suggests that utility restructuring increases risk for all industry segments of a formerly fully regulated industry, including the remaining utility segment. The Public Advocate indicated that the phenomenon predicted by Dr. Kolbe might not apply to electric restructuring as it is envisioned in Maine. In addition, a number of questions were raised regarding Dr. Kolbe's assumptions and calculations. Since we reject Dr. Kolbe's conclusions on other grounds, we will not further discuss his assumptions and calculations here.

Specifically, we reject Dr. Kolbe's conclusions because: (1) it appears that the Company itself questioned them in both its Brief and Mr. Brooks's testimony and (2) the investment community as represented by bond rating agencies Standard & Poor's, Moody's and Duff & Phelps unanimously reject the notion that <u>business risk</u> will be higher for post-divestiture T&D-utilities. We note at least two of the three investment houses cited above (S&P and D&P) have equity investment and research operations and, thus, any argument that their opinion regarding changes in future business risk might not pertain to equity investors is not valid.

The Company's argument that our adoption of either the Public Advocate's or the Advisory Staff's (preliminary) cost of equity recommendations would somehow fail to account for the true riskiness of CMP's T&D-utility are unfounded. As we noted earlier in our discussion of the peer groups, the OPA and Advisory Staff provided us with peer groups of utilities that bracketed the "Low Triple B" to "High Single-A" bond rating ranges. Therefore, the cost of equity point estimates suggested by these peer groups would account for both the position where the fully-integrated CMP is today and where the CMP T&D-utility may be after restructuring. Any notion that a 10.50% allowed rate of return would somehow be commensurate with a water utility is clearly not valid. Exhibit COC-1 of the Bench Analysis shows that the indicated cost of equity for a water utility is in the area of 8.70% (inclusive of a 15 basis point flotation cost adjustment) using a quarterly DCF model. The same exhibit shows that the cost of equity for the riskiest group of fully-integrated electric utilities is between roughly 9.30% and 10.20% (inclusive of a 15 basis point flotation cost adjustment)

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approximately 10.54%.

using a quarterly DCF model. We are therefore satisfied that we have fully accounted for the riskiness of CMP's T&D-utility.

8. Updates Prior to March 1, 2000

The Company has proposed that we revisit the issue of cost of equity again before March 1, 2000. We presume that it is suggesting a full rate of return proceeding at some time prior to the onset of competition. Both Advisory Staff and the OPA have suggested the use of rather simple indexing mechanisms for doing so. The Public Advocate's proposal was the more complex of the two. As proposed by Mr. Hill, we would take the 3-month average of the 10-Year Treasury Bond and the corresponding 3-month average of the dividend yield of C.A. Turner's Water Utility Index as of today and at some point before February 1, 2000. We would then take 75% of the change in yields and adjust our final cost of equity in this phase of the proceeding up or down accordingly. For example, if the 3-month average water utility dividend yield increased by 30 basis points from 4.10% to 4.40% and the 3-month average yield on the 10-Year Treasury Bond increased by 50 basis points from 4.70% to 5.20%, the average change would be plus 40 basis points ((30bp+50bp)/2). Using a 75% adjustment factor, Mr. Hill would increase the CMP's allowed return on equity by 30 basis points (.75 x 40bp) to 10.30%.

b. Analysis and Conclusion

While the Company's suggestion might have some theoretical merit, we believe it is unnecessary. In this phase, the parties and the Commission have expended significant resources addressing the major theoretical issues involved in determining the Company's cost of capital. It is our opinion that the parties have fully informed us on these issues, and we are satisfied that we have adequately resolved them here. We see no benefit in replaying these arguments in Phase II. As for the updating mechanisms proposed by Advisory Staff and the OPA, we acknowledge that we are not in the business of predicting movements in the stock and bond markets. However, comparing current market conditions to historical averages seems to indicate that an indexing mechanism quite likely would prescribe an upward movement in the future. We feel that our final determination of 10.50% as the appropriate cost of equity in this case, a number 35 basis points higher than Advisory Staff's midpoint recommendation, is adequate to account for this possibility and therefore eliminates the need for any further adjustment. Therefore, there will be no update of the cost of capital prior to March 1, 2000, either through an indexing mechanism or through the filing of additional testimony.

D. Capital Structure & Weighted Average Cost of Capital (WACC)

1. Positions Before the Commission

The weighted average cost of capital (WACC) is established by deciding the appropriate proportion of each component of the capital structure and by determining an appropriate cost rate for each of the component parts. The weighted average sum of the components equals the overall cost of capital. In this case the appropriate capital structure has been the subject of considerable disagreement. Company witness Brooks has proposed a rate year capital structure of $732.23 million, comprising 55% Common Equity, 4.86% Preferred Equity, 12.34% Long-Term Debt and 27.80% Medium-Term Notes (MTN'S). Public Advocate witness Hill proposed an alternate capital structure composed of 45% Common Equity, 5% Preferred Equity, 5% Short Term Debt and 45% Long-Term Debt. The Bench Analysis, using a similar but completely independent methodology, agreed with Mr. Hill's findings.

Mr. Brooks's recommendation appears to be based on the premise that an S&P bond rating of A (A2 for Moody's) would be most beneficial for both shareholders and ratepayers. He notes that roughly 60% of the electric utilities rated by S&P in November 1997 were rated AA or A. He also states that a 55% common equity ratio for CMP is necessary for CMP to achieve an "A-rating" and to overcome CMP's "off-balance sheet financing" or imputed debt instruments. The term "off-balance sheet financing" refers to contractual arrangements that require regular payments, one example of which is an operating lease on buildings or equipment. In the case of an electric utility, a more common type of an "off-balance sheet financing" instrument is a fixed-term purchased power contract. Mr. Brooks claims that CMP has an extremely high amount of these "off-balance sheet obligations" for a company its size. At various times in this proceeding he has used $90 million, $120 million and $180 million as the additional amount of debt imputed to CMP by S&P. Mr. Brooks also argues that the use of Short-Term Debt is inappropriate in utility regulation, stating that it does not truly represent permanent capital, but is rather an interim funding source.

Mr. Hill's analysis consisted of a survey of the capital structures of *Value Line's* Eastern Electric utilities as of year-end 1997. He recommends that CMP target a capital structure of BBB for the near term and calculates that BBB-rated electric utilities had an average actual capital structure comprising 42.6% Common Equity, 5.5% Preferred Equity, 44.5% Long-Term Debt and 7.4% Short-Term Debt. Hill Pref. Dir. Test. at Exh. SGH-1, page 2. Regarding "A-rated" electric utilities, Mr. Hill observes that this group of companies had an average actual year-end 1997 capital structure comprising 45.3% Common Equity, 5.2% Preferred Equity, 42.9% Long-Term Debt and 6.6% Short-Term Debt. Mr. Hill's analysis does not take into account any "off-balance sheet financing" or imputed debt. We note that if he had, the average common equity ratios of the companies he surveyed would have systematically shifted downward. Despite his findings, Mr. Hill recommends a common equity ratio (45%) that is commensurate with A-rated companies rather than BBB-rated companies.

To arrive at his final weighted average cost of capital result of 8.45%, Mr. Hill redistributed Mr. Brooks's capital components by spreading his "extra" common equity capital (of approximately $73.22 million) about equally between Short-Term Debt and Long-Term Debt. He also apparently spread the Long-Term Debt portion about equally between Long-Term Debt and MTN's in order to arrive at the embedded Long-Term Debt cost rate of 7.52%. Mr. Hill adopted a 7.11% cost of Preferred Equity and a 6.41% cost of Short Term-Debt in his final recommendation based on embedded cost rates at December 31, 1997 as provided by the Company.

The Bench Analysis, which provided the greatest amount of industry data to guide us in determining an appropriate capital structure, supported Mr. Hill's recommendation. The Bench Analysis included the average actual capital structures of most of the *Value Line* universe of electric, water and gas LDCs for 1995, 1996, and 1997. As was the case with Mr. Hill's analysis, this survey did not include "off-balance sheet obligations" which would have had the effect of reducing the common equity ratios across the board.

2. <u>Analysis and Conclusion</u>

The Company's request for a 55% common equity ratio is outside the reasonable range based on the evidence as presented. The Company's witness Dr. Kolbe testified:

> The best evidence on the location of the minimum cost capital structures for a company will come from the observed range of a (non-distressed) sample of firms in that company's business . . .

This is precisely the methodology employed by both Mr. Hill and the Bench Analysis. As we have noted, it is indisputable that had Mr. Hill and Advisory Staff included "off-balance sheet obligations" in their respective studies, the actual common equity ratios they found for the industry would have been at least somewhat lower. The Company stated on several occasions that CMP's "off balance sheet obligations" were high for a company its size. However, CMP did not show that imputing a given level of debt to account for its "off-balance sheet obligations" would have pushed it outside a reasonable common equity range for a given bond rating. We may have reached a different conclusion had Mr. Brooks provided us the "adjusted actual common equity" ratios by bond rating class. If, for example, CMP had an produced an S&P or Moody's report showing industry-wide common equity ratios adjusted for "off-balance sheet obligations" that indicated that a "book" common equity ratio of 45% for CMP would have resulted in an *adjusted* common equity ratio that was obviously out of line with industry norms, we may have considered allowing a higher equity ratio.

Generally, we do not determine capital structures based solely on bond rating criteria or the stated goal of a company to achieve a certain rating. Instead, we set a capital structure that is based on cost efficiency. This means that the utility in question should resemble the majority of its industry peers so that it will be able to attract capital on reasonable terms. The evidence in this case shows that the electric utility industry is primarily rated in the “Triple B” to “Single-A” bond rating range, and we are satisfied that a capital structure with a 45% common equity component is reasonable for a T&D-utility. However, as we stated previously, we recognize that a level of uncertainty accompanies CMP’s (and the industry’s) transition to a T&D-only utility and this must properly be reflected in our final decision. It is also in the interest of all the affected parties that Maine’s electric utilities enter the era of competition in financially sound condition. We will therefore take a cautious approach and allow CMP a common equity ratio of 47% rather than 45% to reflect these concerns. We note that while a 47% common equity ratio appears consistent with that of an AA-rated electric utility on average, it is not outside a reasonable range for the Triple-B/Single-A rated electric utilities shown in the Bench Analysis.

We will adopt the capital structure shown in the table below for CMP’s T&D-utility. While we have chosen not to include a Short-Term Debt component in the Company’s capital structure at this time, we do not agree with CMP’s premise that Short-Term Debt is not a “permanent” source of capital for a utility. On the contrary, the evidence presented indicates that the vast majority of utilities commonly employ Short-Term Debt. We will remove the Short-Term Debt component from CMP’s capital structure at this time primarily because the Company’s Medium Term Note (MTN) program appears to provide it with the necessary flexibility to permit efficient financing at a reasonable cost. We will use a capital structure comprised of 47% Common Equity, 4.86% Preferred Equity, 35.80% Medium Term Notes and 12.34% Long-Term Debt. We also adopt the embedded cost rates recommended by the Company for Preferred Equity, MTNs and Long-Term Debt.

Overall Weighted Average Cost of Capital

Capital Component	Percent of Total	Cost Rate	Weighted Average Cost of Capital	Pre-Tax WACC*
Common Equity	47.00%	10.50%	4.93%	8.34%
Preferred Equity	4.86%	4.05%	0.20%	0.33%
Med.Term Notes	35.80%	7.00%	2.51%	2.51%
Long Term Debt	12.34%	8.48%	1.04%	1.04%
Total	100.00%		8.68%	12.22%

•Tax Rate is 40.8% per CMP (Brooks Rebuttal Exhibit-15)

As shown in the above table, we find that CMP has an overall weighted average cost of capital of 8.68% and a pre-tax WACC of 12.22%, using the Company's embedded cost rates as shown and an "all-in" cost of common equity of 10.50%.

VII. UPDATES

Due to the complexity of the issues in this matter and the need to commence this proceeding two and one-half years prior to the start of the rate effective year, the parties, as well as the Examiners, have been aware very early on of the need for an update phase as part of this case. We do not, however, expect the Phase II proceeding to be a replay of this phase. We have attempted, through our decisions here, to narrow the number and scope of the issues for the Phase II proceeding. Below is a list of issues which clearly appear to be candidates for updating.

- New revenues and related expenses stemming from new, nontraditional utility services that may be introduced as competition is expanded
- Maine Yankee decommissioning costs
- Electric energy purchases required by the T&D business
- Maine Public Utility Commission, Office of the Public Advocate and Federal Energy Regulatory Commission regulatory assessments
- Electric Lifeline Program costs
- NEPOOL receipts and payments, including revised transmission charges
- O'Connor site clean up costs
- Actuarially determined post-employment benefit costs
- Actuarially determined workers' compensation expense
- Possible revenues to be received from Florida Power & Light Company ("FPL") relating to a support services agreement for use of CMP's computer hardware and software assets
- Assets that may be transferred in whole or in part to FPL and/or revenue flow from FPL for use of such assets.

This list is not meant to be exhaustive. At the beginning of Phase II, the parties will be provided an opportunity to comment on what issues should be updated consistent with the decisions reached in this case.

Part 2 - STRANDED COSTS

I. OVERVIEW

A. Statutory Background

In this part of the Order, we address the issue of what amount of stranded costs should be included in rates. The Restructuring Act states that, at the onset of retail access, the Commission shall provide a transmission and distribution utility a reasonable opportunity to recover stranded costs. 35-A M.R.S.A. § 3208(5). As part of this proceeding, the Commission ultimately must set an amount of recoverable stranded costs after calculating the net aggregate value of all divested assets with proceeds exceeding book costs, and then offsetting that excess value against the net stranded costs of CMP's remaining generation-related obligations. 35-A M.R.S.A. § 3208(7). The Act further directs the Commission to rely on market information to the greatest extent possible when setting stranded costs, and to periodically review and correct substantial inaccuracies in the stranded costs of the non-divested assets. 35-A § 3208(2), (6).

For the generation assets and contracts not sold, 35-A M.R.S.A. § 3204(4) sets forth a process whereby CMP's rights to energy and capacity from these resources will be sold at periodic auctions. The prices received from these sales will provide market information upon which stranded costs can be based, and the periodic reselling of the rights will provide opportunities for regular review of the related stranded costs. We discuss this further in the QF stranded cost section of this Order.

B. CMP's Asset Sale to FPL

On January 6, 1998, CMP announced that it had entered into an agreement with Florida Power and Light (FPL) for the sale of all of the Company's hydroelectric and fossil fuel generation assets. The overall purchase price agreed to by CMP and FPL for these assets was $846.0 million. CMP has received all regulatory approvals from this Commission and the FERC necessary to close on the sale. On November 17, 1998, however, FPL filed a lawsuit in federal court in New York seeking a declaratory judgment that it be relieved of its obligations to perform due to a recent FERC ruling on transmission access. FPL's action to void the asset sale agreement has brought into question many of the assumptions on which the parties and the Advisory Staff have relied in estimating CMP's stranded costs in this proceeding. We are still confident, that the asset sale will eventually close. Our decisions and projections in this Order are based on that assumption.[23] Even apart from the

[23]Subsequent to the Commission's deliberations of this matter, on March 11, 1999, the district judge in New York ruled against FPL in its action to void the asset sale agreement. We have been informed that FPL will not be appealing this ruling. While the court's action in New York makes it much more likely that the FPL/CMP deal will now close, the actual closing has not yet occurred. The court's decision in New

uncertainty of the FPL sale, many of the values calculated here are estimates and will have to be updated after the closing of that sale. Our objective in this Order is to establish, in as much detail as possible, the methods that will be used to calculate stranded costs during Phase II of the case.

C. General Method of Calculation

The stranded costs that we set in this proceeding will be reflected in CMP's rates effective March 1, 2000. This amount will combine the value we determine as appropriately available from CMP's asset sale to FPL and the net stranded costs of all other items that meet the statutory criteria for stranded cost treatment. For the generation assets and power contracts not divested by CMP, we will set stranded costs based on the sale period and value obtained pursuant to the first auction process required by 35-A M.R.S.A. § 3204(4).

Regional Waste Systems (RWS) has argued that the Commission must administratively calculate stranded costs over the remaining lives of CMP's generation assets and contracts, and use that amount on a present value basis to set stranded cost charges. We do not adopt RWS's proposed approach. An administratively-determined market value for CMP's fossil and hydro assets would be a poor substitute for the value for these assets as determined by the FPL sale. Docket No. 98-058, Order Part II, (Dec. 17, 1998). In addition, the periodic sale of the output of CMP's non-divested assets and contracts will more accurately measure their associated stranded costs than any administrative projection and better meets the statutory requirements set forth in 35-A M.R.S.A. § 3208(2).

D. Stranded Cost Adjustment Mechanism

Consistent with 35-A M.R.S.A. § 3208(6), we will periodically review the stranded costs of CMP's non-divested assets and contracts, and correct the estimates reflected in then-current rates if substantial inaccuracies exist. Such corrections will, at a minimum, reflect substantial changes in the market value or in the cost or quantity of the related generation. The Company has argued that stranded cost charges should also be corrected for changes in sales volume. The IECG opposes the Company's proposal, arguing that such an adjustment would provide the Company with a greater opportunity to recover stranded costs than exists under the Company's ARP. The Company counters that under traditional regulation, the Company was entitled to full recovery of QF costs under the fuel clause.

The question of whether stranded cost charges should be updated for changes in sales volume may depend on the form of regulation under which CMP is operating after implementation of retail access. We may conclude for example, that an incentive approach that does not include specific adjustments for changes in usage best achieves the objectives of the Act. Therefore, we conclude that this issue can be

York does not cause us to alter the findings or conclusions reached herein.

better addressed after March 1, 2000 when we consider the appropriate form of regulation for CMP after restructuring.

II. AVAILABLE VALUE FROM ASSET SALE

The Company originally announced that the gross sale price of the FPL asset sale was $846.0 million. Of this total, $18.0 million was allocated as the sale price for the assets of Union Water Power Company (UWP), a subsidiary of CMP.[24] On June 16, 1998, the Company entered into a Subsequent Sales Agreement with FPL which provided for the sale of hydro storage facilities and certain related assets and increased the gross sale price to $850.4 million (and increased the amount allocated to UWP to $19.7M.) Using the $850.4 million sale price, the Company estimates the net gain from the sale to be $476.0 million, based on the following calculations:

CMP's Calculation of Available Value

Issue	Updated CMP Proposal
Gross Sale Price	850.4
Union Water Power	-19.7
Gross Sale Price to CMP	830.7
Incremental Power Supply Costs	-63.0
Selling Expenses	-14.7
Employee Transition Costs	-15.1
Net Sales Proceeds	737.9
Projected Net Investment	-232.7
Non-Provided Deferred Taxes	-29.2
Excess Deferred Taxes	0.0
Available Value	476.0

We address the adjustments to the gross sale price in the following sections.

[24]Union Water Power is an unregulated subsidiary which offers a broad range of utility related services to CMP and other entities.

A. Union Water Power

1. Positions Before the Commission

As part of the initial agreement between CMP and FPL, FPL agreed to purchase UWP's ownership interests in the Lewiston Falls dam, the Lewiston Canal System, and certain water rights on the Androscoggin River. In its Supplemental Direct Testimony, filed after the asset sale was announced, the Company proposed allocating $18.0 million of the $846.0 million total purchase price to UWP for the sale of UWP's assets. The Company's witnesses testified that the $18.0 million figure was agreed to as part of the CMP/FPL Asset Purchase Agreement (APA).

In their direct cases, both the IECG and the OPA expressed concern about the amount of the purchase price to be allocated to UWP. Both IECG witness Dr. Silkman and OPA witness Mr. Chernick noted that FPL had not separately bid for the UWP's assets. Instead, the allocation to UWP was done after the bid process was completed and was incorporated into the Purchase Agreement. Mr. Chernick noted that the $18 million allocated to UWP is 30 times UWP's gross investment in the sold plant and 100 times its net investment. Mr. Chernick recommended allocating a portion of the sales price to UWP based on a total sales price to book value ratio. The application of this ratio to UWP's assets yields a valuation of $1.2 million based on gross plant, or $700,000 based on net plant.

Dr. Silkman described a series of complex transactions between CMP, UWP, the City of Lewiston, the City of Auburn, Lewiston Community Enterprises, Cumberland Securities Corporation and Central Securities. In the "Project Agreement" described by Dr. Silkman, the City of Lewiston in 1984 withdrew its application for a FERC license to develop the Monty Hydro Generating facilities and also transferred certain property to UWP to allow CMP to develop the project. In return, the City of Lewiston received a continuing 3.2 million kWh credit on its annual electric bill as well as certain water flow rights on the upper Androscoggin River. Because UWP is now transferring the properties it received in exchange for the price of electricity discount, customers should be made whole for supporting the initial transfer of property. Therefore, Dr. Silkman argues that CMP's customers should be entitled to most, if not all, of the $18 million.

The Bench Analysis raised the issue of whether UWP was entitled to any of the available value from the asset sale since it was unclear, based on the information presented up to that point, whether the particular assets of the subsidiary have been subject to the usual risks and rewards of a competitive business or whether CMP's ratepayers have essentially borne the risk involved in the cost recovery related to the UWP assets. The Staff posed the following two questions for CMP's response:

1) whether, in effect, ratepayers have been in the same or similar position with respect to the UWP assets as if the investment had been included in rate base; and

2) whether proper ratemaking should have treated costs, investments and revenue as not separable from CMP-owned hydro assets and, therefore, above-the-line.

In response to these criticisms and concerns, Messrs. Marsh and Call testified that FPL, and not CMP, assigned the $18 million value to the UWP assets, and given the City of Lewiston's high tax rate, FPL may very well have had an incentive to understate the value of the UWP assets. CMP also stated that it corroborated this value by doing its own "sanity check" and concluded that the value was reasonable. The Company noted that it had contracted with Parsons Main, an engineering firm, which estimated the replacement value of UWP assets in question to be $26.5 million.

The Company also responded to the issue of whether CMP was entitled to the value by stating that UWP's assets have not, with one exception which occurred in the early 1980s, been included in CMP's rate base. As such, the Company's shareholders, not its ratepayers, have been subject to the risk of loss associated with an unregulated competitive environment. In response to Dr. Silkman's concerns, the Company observed that the Project Agreement referred to by Dr. Silkman resolved issues concerning the installation of CMP's Monty Hydro Station, and that CMP, not UWP, benefited from the exchange of assets with the City of Lewiston.

In its surrebuttal filing, the Company updated the amount to be allocated to UWP as a result of the Subsequent Sale Agreement (SSA) reached with FPL. Under the terms of the SSA, FPL will purchase certain additional water storage facilities, some of which belong to UWP, which increase the overall purchase price by $4.4 million. The Company has allocated $1.7 million of the revenue from the SSA to UWP and $2.7 million to CMP. Since the book value of the additional CMP assets to be sold, including CWIP and non-provided taxes, is $11.6 million, the SSA has the effect of decreasing the available value from the sale, and thus decreasing the amount available to offset stranded costs, by $8.9 million.

2. <u>Analysis and Conclusion</u>

Before deciding on the amount of value to be allocated to UWP, we must address the issue raised in the Bench Analysis of whether the Company is entitled to keep any of the gain on the sale of the UWP assets. If the Company is in fact entitled to an amount above book value for UWP's assets, the question then becomes what part of the overall purchase price should be allocated to UWP.

a. Entitlement to Gain on the Sale

The Law Court has provided substantial guidance as to whether or not the Company is entitled to keep any of the gain from the sale of the UWP assets through its decisions in *Maine Water Company v. Public Utilities Commission,* 482 A.2d 443 (Me. 1984) and *Casco Bay Lines v. Public Utilities Commission,* 390 A.2d 483 (Me. 1978).

In *Casco Bay,* the Commission flowed back the gain realized by the utility from the sale of certain vessels through an adjustment to the utility's future depreciation expense. The Law Court upheld the Commission noting:

> It is only equitable that the ratepayers who bear the cost of depreciation and maintenance on the property and the burden of a sale at a loss, should be entitled to benefit from the sale of such property at a gain.

Casco Bay, 390 42d. at 490.

In *Maine Water Company,* the Commission flowed through the gain on the sale of two separate water systems, which were divisions of a parent company that owned five additional regulated water systems/divisions, to the five remaining divisions. The Law Court overturned the Commission's decision, holding that the ratepayers in the remaining five water divisions were not entitled to any gain. The Law Court reasoned that the ratepayers in the other divisions never paid their rates through for any depreciation on the assets in their rates and had not borne any risk of loss on the properties.

When read together, these cases establish the principle that ratepayers are entitled to the gain from the sale of utility property when they have paid through rates for the depreciation of, and maintenance on, the property and have also borne the risk of loss on the property. In instances, in which the property was not supported with ratepayer funds and the owners bore the risk of loss on the property, shareholders are entitled to the gain.

The Company has paid to UWP a significant portion of the revenues generated by the assets to be sold, and these payments have been recovered as a utility expense from CMP's ratepayers. Therefore, an argument might be made that the Company's ratepayers have paid for a substantial portion of the depreciation on these assets and thus satisfied the first prong of the *Casco Bay/Maine Water* test.[25] On the other hand, with only one very brief exception, the UWP assets,

[25]This argument, however, should not be carried too far. The same relationship between ratepayer payments and depreciation expense could be made with respect to <u>any</u> of CMP's regular suppliers; no one, however, would argue that ratepayers gained any ownership interest in, for example, the companies supplying CMP with utility poles.

have not been in the Company's regulated rate base. As below-the-line assets, if they had been destroyed or somehow had become valueless, the Company, as the parent of UWP, and its shareholders, and not the Company's ratepayers, would have been forced to suffer such loss. The Company then, and not its ratepayers, has borne the risk of loss on these assets.

We therefore conclude that CMP's shareholders are entitled to the gain on the sale of UWP's assets to FPL. While Dr. Silkman, on behalf of the IECG, has presented an interesting and complex purchase and sale scenario involving UWP, CMP, the City of Lewiston and other entities, we have not been presented with sufficient evidence to overturn the conclusion dictated by the ratemaking principles established by the Law Court in *Maine Water* and *Casco Bay.*

Having concluded that CMP's shareholders are entitled to receive the gain from the sale of UWP's property, it is necessary to determine how the overall sales price should be allocated between CMP and UWP.

b. Allocation of Sales Price

There does not appear to be any controversy over the allocation of the revenue that will be received under the SSA. None of the parties, either during hearings or in their briefs, questioned the allocation of the $4.4 million of additional revenue from SSA. We are satisfied, based on the information provided by the Company, that the allocation of $2.7 million to CMP and $1.7 million to UWP is reasonable. The only controversy concerns the allocation of the $18.0 million of revenue from the original APA.

As discussed previously, the original APA reached between CMP and FPL contained a specific provision stating that of the total sale price ($846.0 million), $18.0 million would be allocated to UWP. The Company originally stated that the book value of the assets to be sold to FPL as part of the original asset sale was $180,000. The Company later stated that this amount was wrong and that the correct value was $400,000. Accepting the Company's correction, the value from the sale which the Company seeks to allocate to UWP is approximately 45 times the book value of the assets. In addition, the UWP assets being sold to FPL have an assessed value for property tax purposes of $3.6 million, or approximately one-fifth of the value allocated by CMP. While it is not unusual for an asset's sale price to exceed its book value or the value assessed for property tax purposes, we find that the size of the discrepancy here certainly justifies the concerns expressed by Mr. Chernick and Dr. Silkman that CMP overallocated value from the sale to UWP.

In its brief, the Company argues that the Law Court has approved of at least three standard appraisal methods for determining the market value of real property: (1) the "comparative" or "market data" approach; (2) the "reproduction cost less depreciation" or "cost" approach; and (3) the "income" or "capitalization" approach. *Shawmut Inn v. Town of Kennebunkport,* 428 A.2d 384, 390 (Me. 1981). The three approaches to valuation presented in *Shawmut Inn* provide a reasonable basis for evaluating the evidence on the value of the UWP assets in this case.

The Company claims that the sales price stated for the UWP assets in the APA definitively establishes the market value of the UWP assets being sold. We do not agree. Pursuant to the Commission's approved asset sale plan, CMP put its generation assets out for bid in two bundled packages: a hydro package, which included the UWP assets and a fossil package. FPL bid on both the hydro and the fossil components and was selected the winner of both packages by CMP. At no time during the bid process, did CMP either solicit or did FPL make a specific bid on the UWP assets. Subsequent to selecting FPL as the winning bidder, CMP asked FPL to allocate a share of the purchase price to the UWP assets. FPL's designation of the $18 million value was not part of an independent arms length transaction and had no impact on the total price that FPL would pay CMP. FPL's allocation was not the basis for an actual sale and therefore, does not establish the market value for the UWP assets.[26]

Mr. Chernick has testified that FPL's UWP allocation, made in the course of the lengthy post-bid negotiation process, would provide value to CMP's shareholders without any additional sacrifice by UWP. CMP counters that there is no real evidence to indicate that allocation was part of any bigger bargain and that FPL, if anything, had an incentive to understate the valuation given the high tax rate in Lewiston. We agree with CMP that there is no evidence to demonstrate that FPL gained anything by establishing an inflated value for the UWP assets. Nor, however, can we isolate FPL's post-bid allocation of the price to be paid for the UWP asset and state that it, standing by itself, either makes sense from FPL's economic perspective or in any way definitively establishes the value of these assets.

There is, moreover, another reason we are unwilling to accept the value placed on UWP by the contract-even if, as CMP claims, the figure was chosen entirely by FPL. Under the [Act], CMP has an affirmative obligation to mitigate stranded costs. While we recognize that CMP's management also has an obligation to its shareholders, we find the absence of <u>any</u> record evidence showing CMP's contemporaneous analysis of the market value of UWP - and thus an analysis of whether the $18 million figure presented by FPL was fair to both ratepayers and

[26] In a footnote to its brief, the Company cites a "sanity check" it did on FPL allocation. Due to the highly confidential nature of this material, CMP refrained from discussing this calculation in any detail. Since the "sanity check" calculation does not properly account for the vintage of the plant and the varying levels of corporate investment in the plant, we do not find that CMP's "sanity check" corroborates the FPL allocation or can be used independently to calculate the market value of the UWP assets.

shareowners - to suggest that, at least with respect to the valuation of UWP, CMP was at best indifferent to its obligation to mitigate stranded costs whenever possible.

CMP provided the Parsons Main Study as part of its rebuttal case as support for CMP's $18.0 million allocation. We conclude that the Study does not support the allocation. The Parsons Main Study estimated the construction cost of the UWP assets in 1998 dollars to be $26.4 million broken down as follows:

Dams	$4,117,900
Main Gate House	$1,285,800
Canals	$11,874,900
Bridges	$8,178,100
Mobilization and Misc.	$1,018,300
TOTAL	**$26,475,000**

The major problem with the Parsons Main approach was that it estimates the costs, (and thus arguably value), for a brand new facility. The facilities sold to FPL were not brand new. The Law Court has held that reproduction cost is a valid means of assessing market value for an asset. The reproduction costs, however, must be reduced by depreciation, reflecting reductions for physical depreciation, functional obsolescence and economic obsolescence. *Shawmut Inn,* 428 A.2d at 394. The Parsons Main Study failed to include any such analysis and, therefore, provides no meaningful information as to the market value of the UWP assets.

The third approach set forth by the Law Court in *Shawmut Inn* was the "income" or "capitalization approach." In his surrebuttal testimony, Mr. Chernick calculated the value of UWP assets based on the revenue stream produced by the assets. Mr. Chernick found the average revenues produced by the UWP assets during the period of 1992-1997 to be $146,000. Assuming a 10% discount rate, Mr. Chernick estimated the value of the UWP assets to be $1.46 million. At the hearing, upon questioning from the Company, Mr. Chernick acknowledged that he had incorrectly double-counted the property tax expense on the UWP property in calculating the annual revenue generated by the property. Correction for this error increases the annual revenue stream by $100,000 and the estimation of total value by $1 million to $2.46 million.

CMP argues that if Mr. Chernick's approach is utilized to calculate the market value of the assets, the $2.46 million total should be multiplied by a factor of four, since on an overall basis FPL agreed to pay approximately four times the discounted earnings value of all of the assets sold. We do not believe such a multiple is appropriate. Because the generation assets that FPL will purchase from CMP are currently subject to regulation, the net present value of the expected revenue stream will equal the net book value of the assets. The difference between the purchase price paid by FPL and revenue stream that CMP would otherwise have obtained from its assets reflects the premium FPL was willing to pay for these assets that will be going from cost of service regulation to the unregulated generation market. FPL's expectation, of course, is that when the assets are removed from regulation, the revenue produced will at least equal the expected revenue stream implicit in its bid price. As noted in Section II. (A)(2)(a), UWP's assets have not been in rate base and have not been subject to regulation. Therefore, there is no reason to expect an increase in the revenue stream as a result of restructuring. Indeed, the net present value of UWP's current expected revenue stream is already more than five times its book value.

The revenue stream methodology utilized by Mr. Chernick has been found by the Law Court as one acceptable way to calculate market value. *Shawmut Inn, 428 A2d.* at 390. The Company has not been able to demonstrate why this approach, which produces a value quite similar to the assessed values of the property, should not be used. We, therefore, find that Mr. Chernick's revenue stream methodology, as corrected, provides the best indicator of market value of the UWP assets.

Combining the $1.7 million of the value attributable to UWP from the SSA and the $2.46 million allocated to UWP under the Chernick methodology produces a total allocation of $4.16 million. We believe, however, that some upward adjustment is warranted to the overall evaluation to reflect the fact that a major portion of the revenue produced by the UWP assets was provided by its affiliate, CMP, and therefore, may not have been a true market rate. Therefore, to reflect this fact we will increase the APA allocation by $2.34 million, resulting in a total allocation to UWP of $6.5 million.

B. Employee Transition Cost

In its initial filing, CMP proposed that it be allowed to deduct $15.1 million from the asset sale price for the estimated cost of employee transition benefits. The Company argues that it is entitled to recover these costs with the proceeds from the asset sale since they represent costs of the asset sale. In its surrebuttal filing, the Company revised the total estimate to $15.6 million based on more current information. The following table presents the Company's original and revised estimates by category for employee transition costs:

	AMOUNT ($000,000)	
ITEM	**ORIGINAL**	**SURREBUTTAL**
Enhanced Severance Benefits	$2.0	$1.0
Early Retirement Benefit Enhancements for both Pension and Post Retirement Medical Benefits	$8.1	$8.1
Pension and Medical Plan Curtailment Costs Pursuant to SFAS 88 and 106	$4.0	$5.5
Reserve for NEHI to Fund Unvested Portion of Post-Retirement Benefits of Transferring Employees	$1.0	$1.0
TOTAL	**$15.1**	**$15.6**

In their Bench Analysis, the Advisory Staff recognized that legitimate employee benefit costs mandated by the statute should be borne by ratepayers, However, the Staff recommended that legitimate incremental costs be included as part of the T&D utility's revenue requirement rather than deducting an estimate of those costs from the asset sale price, thereby affecting the available value. Based on the Company's description of these costs in its annual ARP filing, the Staff stated that it appeared that only the Company's $1.0 million "payment in reserve to NEHI"[27] may properly be considered a cost directly associated with the transaction which should be deducted from the sale price in calculating the available value.

CMP argues that the costs CMP is seeking to have deducted from the value of the sale constitute legitimate costs directly related to the divestiture of the assets. CMP further maintains that requiring the Company to establish a regulatory asset to recover those costs, as opposed to allowing recovery through a deduction from the proceeds of the asset sale, "elevates form over substance through a hyper-technical reading" of the statute. We disagree that including the Company's proposed employee transition costs as an ongoing cost, as opposed to an offset to value from the sale, is a mere technicality.

To qualify as a deduction from the sale proceeds we believe employee costs should meet three criteria. First, the costs must be legitimately recoverable from ratepayers. Second, the costs must be known with sufficient certainty. Third, the costs must arise or have been incurred as a direct result of the sale.

Of the employee transition costs sought to be deducted from the sales price, we find that the "Reserve for NEHI to Fund the Unvested Portion of Post-Retirement Benefits of Transferring Employees" satisfies all of the criteria set forth above. This cost is specified in the asset purchase agreement; it is part of the transaction, in that this amount will have to be paid by CMP to FPL at the asset sale closing under the terms of the APA; and finally, it is legitimately recoverable from

[27]NEHI stands for National Energy Holdings, Inc., now known as FPL Energy Maine, Inc.

ratepayers because this payment will allow employees of CMP who transfer to FPL to receive credit for their service at CMP in calculating their post-retirement benefits. Thus, the payment of this benefit prevents CMP employees who transfer to FPL from being unduly harmed by the transfer and, therefore, is properly recoverable from ratepayers under 35-A M.R.S.A. §3216. *See* Part C, Section III (D), above. We conclude, however, that the costs associated with the remaining employee transition programs should not be used to offset the value from the sale but rather should, to the extent they are found to be recoverable from ratepayers, be included in the Company's revenue requirement.[28]

There are several reasons why the other claimed costs fail to meet the criteria set forth above. First, as evidenced by the Company's updates to these cost calculations and by the Company's repeated responses to data requests, most of the employee transition costs requested to be offset are still only estimates. In many instances, employee transition program costs will not be known until well after the asset sale closing. Second, we find that the costs, other than the direct payment to NEHI, are not related to the FPL asset sale, but rather are costs associated with restructuring in general. The Legislature anticipated that certain employees might be adversely affected by restructuring, and therefore, required utilities to provide certain mandated benefits for these individuals. 35-A M.R.S.A. § 3216(2). The Legislature required that the reasonable incremental costs of the benefits required by section 3216 be recovered from ratepayers through charges collected by the T&D utility. The Commission's Employee Transition Benefits Rule provides that the recoverable costs of a utility's employee transition benefits program will be reflected in rates *after* electric restructuring is implemented on March 1, 2000. Chapter 303 § 5(C). Finally, as set forth more fully in Part 1, Section III(D) above, we find that some of the costs associated with CMP's discretionary employee transition programs may not be recoverable from the Company's ratepayers.

Delaying recovery until March 1, 2000, then, is not a mere technicality. By delaying recovery of employee transition costs until the start of restructuring, the Commission will be able to determine the actual level of employee transition costs that qualify for recovery under Chapter 303. We will, however, allow the $1.0 million to be paid to NEHI at the time of closing for the post-retirement medical benefits of those employees who transfer to FPL, to be used as an offset to the value from the sale.

C. Estimated Selling and Transaction Costs

CMP proposes that $14.7 million be deducted from the available value associated with the sale for selling and transaction costs (e.g., consultant and legal fees, costs of document center) . We agree with CMP that such costs are appropriately deducted from the sales price. CMP's methodology for calculating these costs was considered and was implicitly approved in *Central Maine Power Company, Divestiture*

[28]The revenue requirement treatment of CMP's proposed employee transition costs has been discussed previously in Part 1, Section III (D).

of Generation Assets - Request for Approval of Sale of Generation Assets, Docket No. 98-058. As Part of Phase II, this amount will be updated after the asset closing and be reconciled to the actual transaction costs incurred.

D. <u>Transitional Power Supply Costs</u>

In the sale of assets case, the Commission found the transitional power supply agreement with FPL to be reasonable. As the agreement calls for fixed prices, we find it proper to deduct the net buyback costs from the sale proceeds. The buyback costs, however, are not incurred until after the closing of the asset sale. We agree with CMP's general approach of calculating the net buyback costs by deducting CMP's revenue requirement associated with the sold assets from the FPL buyback costs. The number, though, cannot be calculated accurately until after closing.

Assuming the asset sale is closed, CMP may receive additional wheeling revenue from FPL prior to the implementation of retail access. Our view is that it is reasonable to offset the buyback costs with the additional revenues that will be obtained between the closing and March 1, 2000. In CMP's exceptions to the Examiner's Report, the Company argued that it did not expect to receive any additional wheeling revenue from FPL during the transition period. We will seek to confirm this fact during the Phase II proceeding. If the Company is correct in its assertion, obviously no offset will be made. Wheeling revenues obtained after March 1, 2000 should be accounted for in the revenue requirement calculations.

According to CMP, in the 1998 ARP Annual Proceeding the early termination of the purchase agreement between CMP and AVEC results in savings to CMP. Docket No. 98-221. The AVEC savings also should offset the buyback costs. CMP should calculate these savings in its Phase II filing.

E. <u>Post-1995 Investment</u>

After making the allocations and cost offsets discussed above, we must next deduct from the sale price the net book value of the assets being sold to calculate the gain or loss from the sale. In accounting terms, this is a relatively straight-forward process. The gross plant investment, reserve for depreciation and reserve for deferred taxes related to the assets being sold are readily determined from the Company books of account, including its property records. For purposes of calculating stranded costs, however, the Commission may not include investments made after April 1, 1995, except that the Commission may include obligations incurred between April 1, 1995 and March 1, 2000, that are beyond the control of the utility or obligations incurred after April 1, 1995 to reduce potential stranded costs. 35-A M.R.S.A. § 3208(3). Subsection 4 of section 3208 goes on to state:

> An electric utility shall pursue all reasonable means to reduce its potential stranded costs and to receive the

> highest possible value for generating assets and contracts, including exploration of all reasonable and lawful opportunities to reduce the cost to ratepayers of contracts with qualifying facilities. The commission shall consider a utility's efforts to satisfy this requirement when determining the amount of a utility's stranded costs.

1. Positions Before the Commission

The Company, through the testimony of its witness Mr. Wiley, discussed the various types of capital projects that were in progress or were undertaken as of April 1, 1995, as well as an estimate of the amount of spending on generation plants since that date. Mr. Wiley described the basis and need for the capital projects at several of the Company's hydroelectric stations, as well as several studies undertaken to evaluate the Company's options for its Wyman and Mason fossil fuel stations. The Company asserts that it has provided sufficient evidence, both generally and specifically, to justify inclusion of its post-April 1, 1995 capital expenditures in the stranded cost calculation. CMP maintains that the evidence it provided clearly shows that its post-April 1, 1995 obligations were incurred either to comply with FERC hydro re-licensing and environmental requirements that were beyond CMP's control or to maximize and preserve the value of the assets that were put up for bid, so that when the assets are eventually sold the Company will receive the highest possible price, and thus reduce it potential stranded costs.

The OPA asserts that CMP has not met its burden of proof with respect to some of the capital spending since April 1, 1995, and therefore, at least $7.1 million should not be included in the amount recoverable from the asset sale value. The Public Advocate says that the Company has relied on many generalizations to support its claim and has not shown that all of the capital spending projects at issue were beyond the control of CMP, as the statute requires. Because CMP has not made specific showings about the need for some of the spending, the OPA argues that the Company has failed to meet the requirements of the statute and, thus, recovery should be denied.

2. Analysis and Conclusion

The law concerning recovery of post-April 1, 1995 investment is clear: CMP must demonstrate that the capital spending it incurred since April 1, 1995, meets the requirements of Title 35-A, section 3208. While the Company has presented a fair degree of both general and specific evidence attempting to show that the spending meets the criteria for recovery, we cannot find that all such spending should be included in the Company's stranded cost recovery calculation. As explained below, the record is unclear as to the amounts that should be disallowed, and thus, some supplemental data must be obtained during Phase II of this proceeding.

With the exception of certain assets included as part of the SSA and discussed below, we will allow all of the expenditures related to the Company's hydroelectric plants to be recovered, as we find the Company has justified these projects as necessary to preserve the assets and to further the Company's mandate to mitigate stranded costs. There is no doubt that the money spent on re-licensing requirements and maintaining the condition of the dams and generating stations allowed CMP to receive a very favorable price when it put the assets up for sale.

As for the capital spending made on the Company's fossil fuel plants, we find that some of the amount claimed should not be recovered from CMP's ratepayers. Specifically, we will allow the Company to recover the spending on actual physical replacements or upgrades at the Wyman and Mason Stations, but we will not allow recovery of expenditures for any studies that the Company has undertaken at these plants, as described by Mr. Wiley. Specifically, we disallow recovery of the studies done by Stone and Webster Engineering Corporation to determine the feasibility of adding natural gas firing to Wyman Units 3 and 4 while retaining oil firing capabilities. We also find that the studies concerning the viability of running the Wyman units on Orimulsion do not meet the requirements for inclusion and should be disallowed. We will also not allow recovery of the engineering pre-feasibility studies that were conducted to evaluate the repowering of Wyman Units 1, 2 and 3 and the Mason Station Unit to combined cycle configurations.

While the studies may have been valuable to the Company as it contemplated its various options for operating the plants, there is no evidence that CMP provided the results to any of the potential buyers or that it received additional consideration from any of the bidders because of the studies. There is also no evidence to support the Company's claim that the studies provided it with valuable information that was used in the process of negotiating the terms of the sale agreement. The studies may have had value to CMP, but the Company has failed to prove how the studies meet any of the expenditure exceptions defined in the statute.

Unfortunately, despite the extensive record in this case, we can find no evidence that indicates precisely the amount of the costs incurred for the feasibility studies that are subject to non-recovery. CMP witness Mr. Wiley describes the studies in his testimony, and his exhibit numbers 6 and 7 show book balances and annual spending amounts, but we cannot deduce the specific amounts related to the studies in question. Similarly, Mr. Chernick for the OPA provides a schedule on page 8 of his surrebuttal testimony that purports to show the total amount of capital spending on generation projects since April 1, 1995. We note that the 1997 and 1998 amounts on that schedule are based on estimates, not actual spending. In any event, this schedule does not aid us in identifying the spending amounts that we disallow. Finally, Exhibit Marsh/Call-3, included in those Company witnesses' updated and rebuttal testimony, claims to show the generation-related capital expenditures from April 1, 1995 to December 31, 1996. Again, the delineation in the exhibit is not project-specific enough to identify the feasibility studies.[29] The Commission directs CMP to supply the costs of the studies as part of its Phase II filing.

In addition, during Phase II CMP should provide a description of and justification for the amounts described as “CWIP/PREL ENGIN” on Exhibit Marsh/Call-12. This exhibit shows the book and tax values for the additional hydro assets of CMP and UWP that were subsequently included in the sale to FPL. Specifically, we want to ascertain whether the amounts shown in the total of $2.9 million are considered Construction Work in Progress or Preliminary Engineering. To the extent any of the latter is included, the Company should fully describe its purpose and justify its inclusion as an offset to the sale price.

F. Non-Provided Deferred Taxes

The final step in calculating the available value from the sale is factoring in the tax consequences of the sale. The Company proposed removing $29.2 million in value to account for non-provided deferred taxes. No party has contested this particular adjustment. We accept the adjustment, which must be updated to reflect the delayed closing.

G. Investment Tax Credits

Significantly controversial in this case has been the disposition of the Company’s unamortized Investment Tax Credits (ITCs) that have been recorded for the assets being sold to FPL. Similar disagreement has arisen over treatment of the Excess Deferred Income Taxes (EDITs) related to the assets being sold. CMP estimates that at the time of the sale of its generation assets it will have about $15.2 million in unamortized ITCs remaining on its books. These tax credits were claimed by the Company on its federal tax returns for years when the credit was available; the credit was phased out by the Tax Reform Act of 1986 (TRA 86). Under the provisions of the TRA, regulators were prohibited from flowing back these tax credits to ratepayers any more rapidly than ratably over the regulatory (i.e., book depreciable) life of the assets that generated the ITC. In effect, Congress gave utilities an interest-free loan, supposedly to encourage capital investment, and denied regulators any discretion as to how quickly ratepayers would receive the benefits of this credit in their rates.

[29] In its exceptions to the Examiner’s Report [in response to a request from the Examiner’s, the Company stated that it has only expended $66,000 on Wyman related gas-conversion feasibility studies. The Company also claimed that the Orimulsion study was done before April 1, 1995, and therefore, should not be excluded. We will verify these factual claims as part of the Phase II proceedings.

1. Positions Before the Commission

CMP has been amortizing its ITCs in accordance with the federal tax statutes. Now that the Company is about to sell its generating assets, the disposition of the balance of the ITCs on the Company's books must be determined. CMP asserts that the Internal Revenue Code (IRC) and corresponding Internal Revenue Service (IRS) Regulations and Private Letter Rulings (PLRs) regarding normalization of ITCs require that any unamortized ITCs be retained by the Company, and prohibit using any balance to reduce, in any way, the Company's rate base or cost of service. Any violation of tax normalization rules would subject CMP to "enormous tax penalties", which, according to the Company, means that it might be prevented from claiming accelerated depreciation and be required to recapture all unamortized investment tax credits for open tax years.

CMP has cited several PLRs by the IRS which it claims are "uncontroverted evidence" and "controlling legal authorities" on the subject. The underlying rationale of the PLRs presented by the Company is that once property ceases to be "public utility property" all entries related to that property must be removed from the regulated books of account that are used as the basis for setting the utility's rates. Since ratepayers are no longer responsible for the return of, and on, the property, any ITCs related to that property may no longer be flowed back to the ratepayers. The IRS has opined that the unamortized ITCs must be transferred to non-regulated status on the utility's books, effectively allowing the utility to retain any remaining benefit. According to CMP, the premise of the rulings is "fundamental symmetry," with ratepayers paying the cost of service for the plant and also receiving the tax benefits that accompany the property. When the property is removed from regulated service, the unamortized ITCs must likewise be removed from cost of service calculations. Further, the IRS is vested with broad authority to prevent any attempts to circumvent the intent of the Tax Code that ITCs be retained by the utility. CMP also suggests that if the Commission is inclined to accept the recommendation propounded by the OPA and Bench Analysis, it should require CMP to seek a PLR from the IRS. The Company asserts that the Commission and the OPA (to a limited degree) could participate in the PLR process. This would provide a conclusive decision on the ITC and EDIT issues.

The Public Advocate argues that the unamortized ITCs should be returned to ratepayers, and that CMP has ignored the equities of the situation and misstated the law. The OPA claims that CMP's position with regard to ITCs and EDITs stands in contrast to its claim that ratepayers owe it the value of the FAS 109 deferred non-provided taxes that are also on its books. The Public Advocate asserts that CMP wants it both ways. On one hand, it seeks to be paid by ratepayers for the non-provided taxes that it has accrued, while on the other the Company wants to retain the benefits of the ITCs and EDITs that have been recorded on its books. The OPA also maintains that symmetry and cost-of-service ratemaking principles require that any deferred tax balances be returned to customers when the underlying assets are sold.

The OPA also notes that during the debate about these provisions prior to the enactment of TRA 86, the utility industry promised Congress that it would return these tax benefits to ratepayers, as long Congress prevented regulators from doing so over less than the assets' regulatory lives. Now, according to the OPA, CMP wants to go back on that promise by retaining the tax benefits for itself.

Further, the OPA asserts that the tax laws and FERC accounting regulations compel that the ITCs and EDITs on CMP's books be flowed through to ratepayers at the time of sale. The OPA points to a section of the IRS regulations that says the deferred tax reserves are to be "properly adjusted to reflect asset retirement." The OPA then asserts that under FERC accounting rules, the sale of assets is a retirement which is recorded on the books through the use of the accumulated depreciation account. Although not shown on the OPA's example of the accounting entries necessary to record an asset retirement, the OPA apparently argues that any unamortized ITCs and EDITs should be similarly accounted for on CMP's books. That is, they should be credited to the depreciation reserve account for disposition by the controlling regulatory authority.

Finally, the OPA points out that the PLRs cited by the Company contain the caveat that each applies only to the specific taxpayer who requested it and the result is dependent on the specific facts in question for each case. The Public Advocate asserts that the cited PLRs were all obtained at the initiative of utilities, and the facts and arguments presented by the utilities were tailored to achieve the result most favorable to the utility. Because no regulatory agencies or ratepayer advocates provided any input during the PLR process, no consideration was given by the IRS to the effects of the rulings on ratepayers. The OPA also argues that it is not surprising that no contrary PLR exists since, if the IRS were about to issue a PLR adverse to the utility's interests, the utility would likely enter into a settlement rather than risk release of an unfavorable PLR. Finally, the OPA points out that none of the PLRs cited by CMP deals with the issue of recovery of stranded costs, as is present in the instant case.

2. Analysis and Conclusion

The issue of the proper ratemaking treatment of the unamortized ITCs on CMP's books presents a very difficult choice for us. Even evaluating the Company's claim that a violation of the normalization requirements would subject CMP to "enormous tax penalties" is a difficult task. Mr. Seltzer's rebuttal testimony indicates that 1991 is the Company's earliest open tax year, but we can find no other corroboration of that fact. No matter which tax years are still open, we can find no record evidence concerning the magnitude of the potential tax liabilities that the Company might incur if the IRS found that it violated tax normalization requirements. It does appear that the Company would, in fact, be ineligible to claim accelerated depreciation on its remaining public utility property.

There is no doubt that absent federal tax laws requiring a contrary result, appropriate ratemaking principles and the equities involved would lead us to conclude that the ITCs should be returned to ratepayers through the available value calculation at the time of the sale of the generation assets. In all of the PLRs of which we are aware, however, the IRS has consistently held that the federal Tax Code mandates that when public utility property is removed from service for any reason, including sale, the related ITCs and EDITs cease to exist on the regulated books of account of the utility. Therefore, the IRS reasons that those ITCs and EDITs cannot be used in any way, either directly or indirectly, to reduce the utility's rate base or its cost of service. Because once public utility property is removed from service, ratepayers no longer are responsible for paying for the cost of the property, the IRS holds that the Tax Code requires that the associated ITCs and EDITs are no longer available as credits to regulated cost of service.

While we believe the conclusion reached consistently by the IRS in its PLRs is unfair and unjust from a ratemaking standpoint, we would not want to jeopardize the Company's ability to claim accelerated depreciation or cause CMP to incur substantial additional tax liabilities because of a decision on our part that runs contrary to the Tax Code, as interpreted by the IRS. Although the Public Advocate has presented us with compelling arguments for the return of the ITCs to ratepayers, he has not provided us with a firm legal basis on which to do so. His presentation of the FERC accounting rules shows essentially how the asset sale will be recorded on the Company's regulated books of account, but it does not dispel the basis for the IRS's prior determinations that unamortized ITC balances on a utility's books cannot be used either directly or indirectly to reduce cost of service after the property is removed from the regulated books of account. Also, while it is true that each PLR contains standard disclaimer language regarding the non-precedential nature of the ruling, it appears that the IRS has been consistent in its interpretations of the regulations regarding ITC balances.

Although equity and sound regulatory policy would lead us to conclude that CMP should be required to return its unamortized ITCs to ratepayers at the time of the sale of its generating assets, we are reluctant to risk the severe tax consequences that might ensue. Thus, we require CMP to seek a Private Letter Ruling from the IRS on the subject. In its request for such a ruling, CMP must indicate to the IRS that the Commission and the OPA should be allowed to participate to the fullest extent possible consistent with applicable statutes.

We take this step because we believe the IRS has not addressed the matter of unamortized ITCs in the context of electric restructuring and the related sale of assets mandated by a state restructuring statute, particularly a statute that requires a utility to take all possible steps to mitigate its stranded costs and provides the utility with a full opportunity to recover its stranded costs which include non-provided deferred taxes. We find it difficult to accept that Congress, when considering TRA 86, had in mind that utilities would be able to retain the benefits of the

ITCs associated with public utility property that was sold after the ITCs had been claimed. It seems unlikely that Congress considered the circumstances where, as here, the property is sold as part of a process mandated by a state legislative directive to restructure the electric industry. We intend to provide to the IRS all appropriate arguments supporting the ability of regulatory bodies to return unamortized ITCs to ratepayers.

If, at the conclusion of the PLR process that we have ordered the Company to initiate, the IRS remains steadfast in its previous interpretations of the Tax Code with regard to unamortized ITC balances, we do not rule out pursuing the matter through the appropriate judicial forum. Nor do we rule out seeking a change in the tax law that would allow the more equitable regulatory result of returning any unamortized tax balances to ratepayers.

In light of our decision to require CMP to seek a PLR concerning the status of the unamortized ITCs related to CMP's generation assets that are to be sold, we will require CMP, when it records the sale of its generation assets, to maintain and separately identify as a deferred liability the unamortized ITC balances on its books of account at the time of the sale so that any future disposition allowing flow-through can be fully implemented. The ITCs will not be included in the rate base of CMP, nor will any carrying costs be accrued on the deferred amount. The balances will simply be held in a suspense status until their status is resolved.

H. Excess Deferred Income Taxes

Similar to the amounts recorded for unamortized ITCs, the Company has on its books excess deferred income taxes of approximately $4.2 million that it recorded and collected from ratepayers when the federal tax rate was higher than it is today. As a result of the tax decrease, more taxes have been deferred than were, or are, necessary to meet the tax obligation when the tax-timing differences between book and tax balances reverse themselves. These EDITs represent balances that arose under full normalization accounting practices when the corporate tax rate was higher than the current rate. The amounts have actually been collected from ratepayers under the assumption that they would ultimately be needed by the utility to meet its tax obligations. Because the assets that gave rise to the excess tax deferral are about to be sold, the excess taxes must be removed from the utility's books along with the normal, i.e. the "non - excess," deferred taxes at the time of the sale.

As with the ITCs discussed in the previous subsection, TRA 86 contained a requirement that EDITs be flowed back to ratepayers no more rapidly than over the regulatory life of the associated assets. Thus, Congress reduced the corporate tax rates but prohibited regulators from exercising any discretion over how quickly to flow back any excess tax accruals to ratepayers who had actually paid the deferred taxes to the utilities. One difference from the tax treatment given to ITCs is that regulators were not prohibited from reducing a utility's rate base by the amount of the EDITs, thus at least giving ratepayers credit for the time value of the excess collections.

1. Positions Before the Commission

CMP asserts that, much like the ITC issue described above, the Tax Code, as interpreted through IRS PLRs, requires that the excess deferred taxes be retained by the Company at the time that the assets are removed from the regulated books of account, such as when a sale occurs. The rationale of the IRS is similar on both tax issues: when the assets are removed from the regulated books, ratepayers are no longer responsible for the cost recovery associated with the asset, so ratepayers no longer get the benefit of the excess tax flowback. Therefore, the Company would retain any excess taxes.

The OPA does not approach this issue separately from the ITC situation previously described. His view is that the PLRs that the Company has cited are distinguishable from the current situation, and that the utility industry promised at the time that TRA 86 was being debated in Congress to return these amounts to ratepayers over the regulated lives of the associated assets. Again, the OPA asserts that now CMP wants to renege on its promise to return the money and instead seeks to keep the money for its shareholders. Also, the OPA argues that the equities involved require that ratepayers receive the benefits of the excess deferred taxes.

2. Analysis and Conclusion

While the general analysis of the excess deferred tax issue is similar to the ITC issue, we note one difference between the two issues, although this distinction apparently has not influenced the thinking of the IRS on this matter. In the case of the ITCs, the Company received a benefit from the government in the form of a tax credit which it did not have to flow through to ratepayers at the time. The Company essentially received an interest free loan because it used the tax deduction to reduce its tax payments, and it retained the time value of the money because the unamortized balance was prohibited from being included in the utility's rate base. With the EDITs, the Company has collected these amounts in rates from its ratepayers over the years since the property went into rate base. CMP has reduced its rate base by the entire deferred tax amount (both regular and excess), so that at least on a present value basis ratepayers were held harmless. Absent consideration of the tax consequences that may be involved, we would find it unreasonable for the Company to retain the amounts it had previously collected from ratepayers for taxes it will never have to pay, and we would order CMP to include the EDIT balances in the calculation of the available value from the asset sale.

Much like the ITC issue previously discussed, we find that the IRS rulings appear to consistently conclude that severe tax consequences will ensue if we require the result that is unquestionably fair from a ratemaking perspective: that CMP should return the EDIT balance to ratepayers at the time of the sale. Therefore, we find that CMP should seek a PLR from the IRS regarding the status of EDITs that are related to the Company's generating assets being sold. Like our holding on the ITC issue, CMP must indicate in its PLR request to the IRS that the Commission and the OPA should be allowed to participate in the PLR process to the fullest extent possible consistent with applicable statutes.

Should our efforts fail to convince the IRS to modify its previously-expressed opinion that EDITs must be retained by utilities upon sale of the related assets, we reiterate that we may seek remedies through the appropriate court(s) of law, and/or we may pursue efforts to have the federal statutes modified in such a way as to prevent the unjust result that will occur if prior PLRs are affirmed in this case.
As with the unamortized ITC balance, we order that when CMP records the sale of its generating assets, it transfer any EDIT balances related to the assets to a deferred account until the issue of the flow-through treatment is finally decided. At the time the assets are sold, the EDIT amounts will be removed from the Company's rate base, will not accrue any carrying costs, and must be maintained as a deferred liability until the Commission orders otherwise.

I. Available Value Estimates Summary

Based on the findings and conclusions contained in the previous sections, the available value from the sale of CMP's divested generation assets is summarized in the table below. The numbers are presented with the caveat that they will require adjustment both to reflect the delay in closing on the asset sale and the future adjudications discussed in the prior subsections.

ESTIMATION OF AVAILABLE VALUE	
Issue	**Estimation**
Gross Sale Price	850.4
Union Water Power	-6.5
Gross Sale Price to CMP	843.9
Incremental Power Supply Costs	-63.0
Selling Expenses	-14.7
Employee Transition Costs	-1.0
Net Sales Proceeds	765.2
Projected Net Investment	-232.7
Non-Provided Deferred Taxes	-29.2
Excess Deferred Taxes/ITCs	0.0
Available Value	**503.3**

III. TREATMENT OF AVAILABLE VALUE FROM ASSET DIVESTITURE

A. Overview

Because the proceeds from the proposed asset sale to FP&L will exceed the book value of the assets, the Commission must address how such excess value should be treated for ratemaking purposes. In its direct filing, CMP proposed to use the excess value to write-off all of its regulatory assets, to write-off its undepreciated investment in Millstone 3 and to establish a "QF offset account" with the remaining excess value.

The Company in its rebuttal filing revised its application of value proposal regarding its Millstone 3 investment. In its revised proposal the Company stated that rather than writing-off its total undepreciated Millstone investment, the Commission should instead establish a Millstone 3 regulatory asset representing the difference between the carrying cost (i.e., book value) of Millstone 3 and its market value, as determined by comparing the plant's expected cost of production with the market price of its output. This "impairment amount" would then be written off with a portion of the available value. The Company's revised position is presented in the table below.

***Revised* Application of Available Value from CMP's Generation Asset Sale (millions of dollars)**			
	Unrecovered Balance @10/1/98	**FAS 109 Deferred Income Taxes**	**Value Needed to Retire Asset**
Abandoned projects	$80.2	$54.8	$135.0
Power Production	$5.9	$1.8	$7.7
QF contract buyouts	$97.8	$1.2	$99.0
TOTAL regulatory assets	$183.8	$57.8	$241.7
Millstone 3	$50.9	$12.6	$63.4
DSM/ELP	$27.8	$1.4	$29.2
TOTAL asset reduction	$262.5	$71.8	$334.3
Ice storm costs			$12.7
QF offset account			$129.0
TOTAL			**$476.0**

B. Regulatory Asset Write-Down Proposals

1. The Inclusion of Regulatory Assets as Stranded Costs

The IECG argues that the Company has improperly classified its regulatory assets as a stranded cost. According to the IECG, only those regulatory assets that were uneconomic prior to restructuring and have been made unrecoverable by restructuring, together with those regulatory assets which were created by the restructuring process, qualify as regulatory assets under 35-A M.R.S.A § 3208(2). Specifically, the IECG cites regulatory assets resulting from a deficiency in the sale of generating assets and the difference between QF power contract and market prices as the only costs which can qualify as stranded costs. The IECG argues that this is the only possible interpretation of the statute, lest the words “made unrecoverable as a result of restructuring” and “to the extent that they qualify as stranded costs” become meaningless.

The Restructuring Act defines stranded costs for restructuring purposes as “a utility’s verifiable and unmitigable costs made unrecoverable as a result of the restructuring of the electric industry required by this Chapter.” 35-A M.R.S.A. § 3208(1). The Commission then is to calculate stranded costs by summing the following costs to the extent they qualify as stranded costs pursuant to subsection 1:

A. The costs of a utility’s regulatory assets related to generation;

B. The difference between net plant investment associated with a utility’s generation assets and the market value of the generation assets; and

C. The difference between future contract payments and the market value of a utility’s purchased power contracts.

35-A M.R.S.A. § 3208 (2). This section goes on to state, however, that the Commission may not include as a stranded cost any costs for obligations incurred on or after April 1, 1995, except that the Commission may include:

A. Regulatory assets created after April 1, 1995 and prior to March 1, 2000 for:

(1) The amortization of costs associated with the restructuring of a qualifying facility contract;

(2) Costs deferred pursuant to rate plans; or

(3) Energy conservation costs;

B. Obligations incurred by a utility after April 1, 1995 and prior to March 1, 2000 that are beyond the control of the electric utility; and

C. Obligations incurred by an electric utility after April 1, 1995 to reduce potential stranded costs.

We agree with the IECG's argument that a statute should not be read to render provisions meaningless. We also note that under general rules of statutory construction, a statute should also be read as whole. *Bolduc v. Androscoggin County Commissioners,* 485 A.2d 655, 658 (Me. 1984). Most fundamentally, however, in interpreting the Restructuring Act, we must give effect to the intent of Legislature by examining the plain meaning of the statutory language used and construing that language in a manner that avoids absurd, inconsistent, unreasonable or illogical results. *Melangor v. Belyea,* 698 A.2d 492 (Me. 1997). After considering the arguments of the parties, we conclude that generation-related regulatory assets which were in existence prior to the time of divestiture are properly includable as a stranded cost within the meaning of the legislation.

First, we note that specific language is contained in the statute that allows generation-related regulatory assets to be treated as a stranded cost. Had the Legislature intended to allow only divested generation and QF-related deficiencies to be included as stranded costs, such costs were already included under the provisions of sections 3208 (2)(B) and (C) and, therefore, it need not have included the language of section 3208(2)(A). The interpretation suggested by the IECG would, render meaningless the Legislature's specific inclusion of regulatory assets as stranded costs.

Second, we note that in section 3208(3), the Legislature excluded costs incurred after 1995, but specifically allowed as stranded costs regulatory assets created as a result of QF restructurings, costs deferred pursuant to a rate plan and DSM costs. Under the IECG's interpretation, such costs could be included as stranded costs for the period during which stranded costs were generally excluded but not prior to such time. We do not believe that the Legislature intended such an apparently absurd result.

The restructuring legislation essentially divides existing integrated utility service into two parts: generation, which will now be unregulated, and T&D. Reading section 3208 as a whole, we believe that generation-related costs that could not be recovered in the market are made unrecoverable as a result of restructuring. Because regulatory assets have no market value, to the extent they are legitimate, verifiable and generation-related, they should qualify as a stranded cost.

Having concluded that generation-related regulatory assets are includable as a stranded cost, we must now consider the proposals presented concerning the recovery of such costs.

2. Abandoned Projects, Power Production, and QF Contract Buyouts

a. Positions Before the Commission

The Company proposes that the available value from the sale of its generating assets be used to eliminate virtually all of the generation-related regulatory assets that remain on its books. The Company has estimated the balances of its abandoned projects, power production and purchased power buyout regulatory assets to be $162.9 million as of October 1, 1998. The largest individual item in the group of regulatory assets is the unamortized Seabrook balance, with an amount of about $77.3 million for the asset and about $54.4 million for FAS 109 non-provided deferred taxes.

The Company argues that its approach is mandated through the requirements of 35-A M.R.S.A. § 3208(7). That section of the restructuring statute provides "that the Commission shall set a recoverable amount of stranded costs after calculating the net aggregate value of all other stranded electricity generation assets."

The IECG objects to the write-off of any generation-related regulatory assets with the available value from the asset sale, because the IECG believes that such assets are not, in fact, stranded costs. As noted in the section above, we do not accept the IECG's arguments on this point. The IECG also argues that allowing the Company to write off regulatory assets with the asset sale proceeds provides the Company with a greater opportunity to eliminate the risk of non-recovery of the regulatory assets than that which had traditionally existed for CMP's shareholders. A regulatory write-off, the IECG argues, essentially securitizes the Company's current regulatory assets by shifting all of the risk for recovery to customers.

b. Analysis and Conclusion

We conclude that there is no absolute requirement that the excess value from the sale be applied specifically to a particular asset or group of assets. The entire balance could conceivably be placed in a "negative regulatory asset," or "regulatory liability" account, which would then be amortized with carrying costs accrued on the unamortized balance. Such an approach has the advantage of giving the Commission maximum flexibility as to when and how these benefits should be flowed through to ratepayers. Such discretion would need to be exercised carefully, however, since amortizing the benefits too quickly would produce large short-term reductions followed by rate increases, while a slower pass-through would provide benefits to future ratepayers at the expense of current ratepayers and would require current ratepayers to pay disproportionately for uneconomic costs unrelated to the cost of providing service.

Based on the facts and opinions contained in the record, our view is that the Company's approach to use the available value to write off its generation-related regulatory assets is a reasonable way to pass through the benefits of the asset sale to ratepayers. By eliminating the amortizations associated with these assets, the Company's current expenses will be reduced. A similar benefit could be achieved through the regulatory liability approach described above and by amoritizing the regulatory liability by an amount equal to the amortization of the regulatory assets. Removing the regulatory assets from the Company's books has the additional benefit, however, of strengthening the Company's balance sheet and making the Company a less risky investment. This decrease in risk reduces the Company's cost of capital and therefore, provides an additional benefit to ratepayers. Such benefit is reflected in our cost of capital analysis. *See* Part 1, Section IV, above.

The Bench Analysis raised questions about the FAS 109 tax balance write-off and proposed that the balance be adjusted to its present value, effectively reducing the amount of recovery needed to eliminate the asset. CMP, through its witnesses Mr. Marsh and Mr. Call, responded that the Company's proposal already was on a present value basis, because upon elimination of the regulatory asset, the Company would be liable for current income taxes on the full amount of the write-down. This occurs because the deferred taxes for the Seabrook regulatory asset have already been flowed through to ratepayers as a result of a prior stipulation. Thus, to keep the Company whole on a after-tax basis, the full amount of the FAS 109 taxes must be included in the amount needed to eliminate the regulatory asset.

We agree with the Company that the entire FAS 109 amount, approximately $54.4 million, should be deducted from the available value of the asset sale in order to fully compensate CMP for the write-off of the regulatory asset representing the unamortized Seabrook recoverable balance. We are persuaded that on a present value basis, ratepayers are not harmed by this result, because the full amount of deferred taxes has already been returned to ratepayers through prior Commission orders.

3. DSM/ELP

Mr. Chernick, on behalf of the OPA, opposes the write-off of the DSM/ELP costs, arguing that such costs are not generation-related. In addition, Mr. Chernick argues that since DSM costs have primarily been incurred as a result of service provided to industrial class customers, writing off such costs with the gain on generation assets would result in a cross-class subsidy. We are in partial agreement with Mr. Chernick's position and therefore, will apply available value from the asset sale to write off 50% of the DSM and ELP balances.

CMP's DSM costs have been incurred pursuant to its least cost planning obligation which was intended to promote lower-cost conservation over the installation of generation capacity. *See* 35-A M.R.S.A. § 3191. Therefore, we view the Company's deferred DSM costs as being, to a great extent, generation-related. This view is certainly reinforced by the fact that the Legislature specifically authorized the Commission to include DSM regulatory assets created after April 1, 1995 as a stranded cost, notwithstanding the April 1, 1995 general stranded cost cut-off date. We also disagree that writing off the DSM assets will result in cross-class subsidies since such costs, historically, have not been allocated to rate classes on an embedded (i.e. cost-causitive) basis.

The Company has proposed to write off only those DSM costs currently approved for rate recovery. Consistent with our holdings in Section II(B) above, we conclude that DSM costs should not be written off with the applicable value unless the amounts are both reasonably certain and have been approved for recovery. Therefore, based on our view of the nature of the DSM regulatory assets, we will allow CMP to write off 50% of the DSM regulatory assets currently approved for recovery with the available value from the sale.

We also believe the ELP regulatory asset to be partially generation-related. We note that this asset is fairly small ($.5 million), and is includable at the Commission's discretion under section 3208(3)(A)(2) of the Restructuring Act. Given the size of the asset and the uncertain nature of future ELP funding mechanisms, we find reasonable a 50% write-off of the current ELP regulatory asset through an offset to the available value.

C. Millstone 3 Write-Off

1. Positions Before the Commission

CMP has a 2.5% ownership share in the Millstone 3 nuclear plant in Connecticut. The Company's share of the plant had a book value of about $67.345 million as of September 30, 1998. The Company has recorded approximately $24 million in non-provided taxes (per FAS 109), and also has recorded EDITs and unamortized ITCs of approximately $7.4 million related to the plant on its books at September 30, 1998. Thus, CMP has a net book investment amount of approximately $84.0 million relating to Millstone 3. Originally, CMP proposed to write off its entire Millstone 3 investment with a portion of the proceeds from the sale of its other generating assets. Any ongoing expenses and revenues from Millstone would then be used in the calculation of stranded costs.

CMP now asserts that under Generally Accepted Accounting Principles (GAAP), after electric restructuring occurs on March 1, 2000, it will be required to recognize an asset impairment for part of its investment in the Millstone 3 nuclear plant, because the plant will no longer be subject to cost recovery under rate of return regulation but rather will be subject to market forces. After restructuring, CMP claims that the market value of its investment in Millstone 3 will be less than the amount recorded on its books, and according to FAS 101, CMP must write down the book value to reflect market value.

Market value is measured either by estimating the price at which the Company's share of the plant could be sold to a willing buyer, or by estimating the net present value of the future cash flows that the Company will receive from selling the output of the plant. Because Maine's statutes allow CMP to recover its stranded costs if those costs meet certain criteria, the Company maintains that it will be able to establish a regulatory asset for the amount of impaired value (i.e. the portion that would be written-off under FAS 101) of its share of the Millstone plant. Using the estimated future cash flow approach, CMP projects that it will remove about $50 million from its net investment in Millstone 3. The Company also assumed a proportional split of the FAS 109 taxes and the EDITs and ITCs, resulting in a new net plant investment amount of $20.567 million and a regulatory asset (equivalent to the FAS 101 write-down) of $63.414 million. Because these amounts represent the value at 9/30/98, they must be adjusted to reflect the amounts at the date of retail access. The Company proposes that part of the available value from the sale of its generating units be netted against the Millstone 3 impairment amount, thus negating the need to create a new regulatory asset that would otherwise be recovered over the life of the plant.

The OPA opposes the Company's proposal for a variety of reasons. First, the minority owners of Millstone, including CMP, have filed suit against the operator of the plant, Northeast Utilities, to recover some of the costs that the minority owners claim were imprudently incurred. Because of this uncertainty, the OPA asserts that determining an amount to be written-off, if any, is premature. Also, the impairment value calculated by the Company is only an estimate, and its true amount cannot be determined until actual market prices for capacity and energy are known. OPA's witness Chernick made several other arguments in his testimony, but the OPA has apparently not adopted any of them. The Bench Analysis suggested that because of the many uncertainties involved with the Millstone plant, none of the available value from the generating unit sale be applied to the Millstone investment.

CMP responded that under the Company's proposal, the Commission would retain the ability to examine the continued prudence of the operation of the Millstone plant, or the prudence of a shutdown decision should that occur. The Company would still have a value for Millstone (the post-impairment amount) on its books, and it would still be calculating any stranded cost amount based on the market price of the power from the plant compared to its production cost. The Company argues that its incentive to get the most out of its investment would not change whether or not the regulatory asset remained on the books or was eliminated through the use of available value from the sale.

2. Analysis and Conclusion

Because of the many uncertainties surrounding the Company's investment in Millstone 3, we will not apply any of the available value from the generation plant sale to CMP's Millstone regulatory asset, at least at this time. We believe the Company will have a greater incentive to pursue its claims against Northeast Utilities, as well as to see that the plant is run efficiently or shut down (whichever is most economical), if the full amount of its investment remains on its books, and thus at risk for continued recovery from ratepayers. It is conceivable that the amount of investment that CMP will eventually be allowed to recover from Maine's ratepayers for Millstone 3 could be substantially less than the amount currently on its books. To avoid any potential accounting or ratemaking problems (e.g., based on retroactive ratemaking prohibitions) over the amount of ultimate recovery, we will require CMP to maintain its full investment in Millstone on its books.

We are also not persuaded that an impairment exists. Under Maine's electric restructuring statute, CMP will be able to recover all prudent costs associated with Millstone 3, although a portion of the recovery may be denominated as a stranded cost. Because the recognition of an impairment may be required for external reporting purposes, we will allow the Company to make the accounting entries necessary to comply with FAS 101 according to its discussions with its outside auditors. The amount of any such impairment, however, must remain on CMP's books as an identifiable regulatory asset.

While we will not permit a netting of any portion of the asset sale proceeds against CMP's Millstone 3 investment at this time, we will review our decision if some of the major uncertainties surrounding the plant are resolved, and the recoverable value of the plant can be ascertained with certainty. This could occur either in Phase II of the current proceeding or at the time of a subsequent examination of stranded cost levels, depending on when additional information becomes available.

D. Ice Storm Costs

In *Central Maine Power Company, Deferral of Ice Storm of 1998 Service Restoration Costs*, Docket No. 98-020, (Jan. 15, 1998), the Commission granted CMP the authority to defer the incremental costs associated with ice storm service restoration. In its rebuttal filing, the Company proposed that it be allowed to recover $12.7 million of incremental costs incurred as a result of 1998 ice storm service restoration through the application of excess value from the asset sale. The Company reported that it had incurred $50.7 million in incremental costs, but that it expected to be reimbursed for 75% of this total through disaster relief provided by the federal government. While we recognize that the Company is entitled to recovery of its prudently incurred deferred ice storm costs, for the reasons set forth below, we do not accept the Company's proposal to offset the available value from the asset sale with the ice storm costs.

First, we would note that the level of recoverable ice storm costs remains uncertain at this time. In November, 1998, the federal government announced that Maine, in total, would be provided with $2.2 million in federal disaster relief funds for costs associated with repairing damage caused to its electric infrastructure by the ice storm of 1998. This obviously was significantly less than expected by CMP. We are aware, however, that this action is being challenged and further relief is being sought. Second, while it is likely that the Company has incurred at least $12.7 million in prudent incremental ice storm costs, the final amount to be recovered by CMP has not yet been subject to regulatory review or been approved by the Commission. Finally, given the magnitude of the costs and the fact that they are clearly not generation-related, we do not believe that it would be appropriate to include these costs as a stranded cost to be recovered from the Stranded Cost Gain Account. We will review the prudence of the deferred Ice Storm costs during Phase II of this proceeding.

At this point, we believe that CMP's prudently incurred, non-reimbursed Ice Storm costs be recovered through T&D revenue requirements over a 2-year period commencing on March 1, 2000. We may reconsider this finding after the amount of federal reimbursement is finally known, and once we are able to determine the impact on rates of such a relatively short amortization period.

E. Asset Sale Gain Account

1. Positions Before the Commission

Even after applying the gain from the asset sale to all of the Company's generation-related regulatory assets, a significant amount remains on the Company's books to be flowed back to ratepayers. The Company recommends that the gain be placed in a regulatory liability account referred to as a "QF offset account" to be amortized over a 10 -to 15-year time period. The amortization would be flowed through to ratepayers as an offset to over-market QF contract costs.

Mr. Chernick proposed that all of the gain from the sale be placed in a regulatory liability account entitled "Restructuring Gain." The account would be used to offset rate base and would be applied to write off only those costs that have been fully justified and only if such write-offs do not impose any adverse tax effects. Finally, Mr. Chernick proposes that the ratemaking impact of the regulatory liability be reflected in retail rates late in 1998 as a Z-factor adjustment in CMP's Annual ARP filling in Docket No. 98-221.

On behalf of the IECG, Dr. Silkman has recommended that the entire amount of available value be placed in a Pre-Payment Fund for use in buying out or restructuring QF contracts or for use in buying out CMP's regulatory assets. Under Dr. Silkman's approach, an RFP would be issued and those entities holding stranded cost assets (both QF providers and CMP as "owner" of its regulatory assets) would submit offers to buy out their assets. According to Dr. Silkman, by putting the available value up for auction, the Commission could leverage the available value and get more than $1.00 of stranded cost recovery for every $1.00 of available value.

2. Analysis and Conclusion

While using the regulatory liability account to offset above-market QF contract costs is one legitimate use for the asset sale revenue, it is not the only legitimate or possible use for this gain. As discussed previously, we believe that within the requirements of 35-A M.R.S.A. § 3208(7), the Commission has a fair degree of flexibility on the disposition of the gain from the sale. Therefore, we will not preordain the use of the value from the regulatory liability account, which we shall refer to as the Asset Sale Gain Account.

Although the Bench asked Dr. Silkman to provide additional details on the operation of an RFP, no further information has been received. We will not pursue Dr. Silkman's RFP proposal without knowing more details about its operation, costs and likely incremental benefits when compared to a QF buyout incentive mechanism and do not adopt Dr. Silkman's QF RFP proposal at this time.

As summarized below, using the amount estimated for available value in Section II and assuming the regulatory write-offs authorized in subsection III(B), result in a estimated balance in the Asset Sale Gain Account of $247 million.

ESTIMATION OF ASSET SALE GAIN ACCOUNT			
	Unrecovered Balance @ 10/1/98	FAS 109 Deferred IncomeTaxes	Value Needed to Retire Asset
Abandoned projects	$80.2	$54.8	$135.0
Power production	$5.9	$1.8	$7.7
QF contract buyouts	$97.8	$1.2	$99.0
DSM/ELP	$13.9	$0.7	$14.6
TOTAL value Reduction	$197.7	$58.5	$256.3
Available Value From Sale			$503.3
Asset Sale Gain Account			$247.0

F. Timing and Amount of Benefit Flow-Through

As part of the annual ARP filing, the Company proposed to decrease its ARP capped rates by 10.3% shortly after the closing on the asset sale to FPL. CMP's rate cap reduction is based on a $70.2 million revenue requirements reduction from the following four categories:

(1) the reduction in depreciation and amortization, and associated taxes resulting from the application of value to write-off the generation-related regulatory assets;

(2) elimination of ELP costs under the assumption that a state funding mechanism for ELP will result from the use of state tax revenues associated with the asset sale;

(3) amortization of the QF offset account; and

(4) reduction in capital costs due to financial savings resulting from use of the proceeds.

No party questioned the Company's proposal to flow through the revenue requirement reductions soon after closing on the asset sale. Dr. Silkman, however, proposed that the decrease be in the form of a temporary credit on customer bills. The Bench Analysis indicated general agreement with the Company's proposal for a decrease after the asset sale closing. The Bench Analysis noted, however, that if the closing on the asset sale were significantly delayed into 1999, the Commission should consider delaying any rate decrease until the beginning of retail access.

While we believe that the asset sale with FPL will eventually occur, we cannot now estimate the exact closing date. Given the delay and remaining uncertainty surrounding the FPL asset sale closing, we do not believe that it would be prudent to order a large rate decrease at the time of a closing that may not occur until just prior to the date of retail access implementation. A large decrease implemented shortly before March 1, 2000, through the application of value from the asset sale to cost of service rates, could very well be followed by an equally large increase at the time of restructuring if the market prices of generation services approach those implicit in the FPL bid prices. Such rate volatility would likely cause customer confusion and dissatisfaction over the restructuring process. Therefore, given the uncertainty as to the closing date, we will not at this time order that any specific decrease occur prior to March 1, 2000.

The regulatory asset write-downs which we authorized in subsection III(B), should occur on March 1, 2000. The Company shall maintain all available value from the time of closing on the asset sale in the Asset Sale Gain Account which shall accrue carrying charges in accordance with the capital savings section below.

G. Capital Savings Resulting from Asset Sale

1. Positions Before the Commission

In calculating the revenue requirement impact of the asset sale the Company calculated its capital savings on a cash basis, adjusted to reflect the capital savings included in the FPL power buy back cost calculation. The cost of capital calculation in the Bench Analysis was done on a book basis, and it was derived by removing from rate base the regulatory assets which were to be written off and including the regulatory liability account which would offset rate base to get the total rate base reduction ($492 million). This amount was then multiplied by the Company's pre-tax cost of capital (11.5%), using the ARP-adjusted return on equity and the Company's current capital structure.

The Bench Analysis asked the Company to respond to the following:

1) Why the Company chose not to calculate the cost of capital reduction on a book basis?

2) What errors did the Company believe Staff made in its book basis calculation?

3) Why the Company's current capital structure should not be used?

4) Why was it necessary to adjust the Company's cost of capital savings by $23.7 million to avoid a double count?

Messrs. Marsh and Call testified that the Company used a 3-step approach to calculate capital savings:

1) Determine the amount of cash that will be provided by the generation asset sale to reduce outstanding capital;

2) Identify required reductions in capital and the savings associated with those reductions,

3) Identify other potential reductions with an appropriate capital structure and savings related to these reductions.

CMP calculated the net cash available by taking the purchase price of the assets sold and then subtracting income taxes and selling expenses. Net cash available was then applied to specific components of the capital structure that could be or were required to be reduced. Specifically, all remaining mortgage debt was eliminated; common equity was eliminated to reduce the equity portion of capital structure to 50% and the remaining funds were used to reduce the amount of pollution control bonds outstanding.

In their surrebuttal testimony, Messrs. Marsh and Call also testified that, even if Staff's rate base approach were adopted, the Staff had incorrectly calculated the rate base reduction because it mistakenly ignored the impact of deferred income taxes on rate base. Messrs. Marsh and Call also testified that the Staff should have used the 10.55% return on equity approved in the last rate case.

2. Analysis and Conclusion

The Commission has historically set rates based on book costs. The Company's approach in calculating the available value and the application of value is consistent with this approach. For capital savings, however, the Company argues that it would be unfair to base such savings on a book basis because the Company may not actually be able to achieve such savings.

Adopting the Company's position on this matter would essentially require us to micromanage the Company's handling of the proceeds from the asset sale. As we discussed in Part 1, Section II, the Company, as part of its effort to adapt to the dramatic changes that are occurring in the electric industry, has reorganized into a holding company structure. As part of its overall corporate strategy, the Company may very well decide that it is in its corporate interest to invest the cash proceeds from the asset sale in its non-core subsidiaries, such as its recently approved LDC venture, rather than seek to raise funds in the market at a later date. The Company could also pay out a portion of the sale proceeds as dividends, or it could buy back its common stock. The Company, at this point, has not committed to any course of action.

We believe these capital resource allocation decisions are best left to CMP Group, Inc.'s, management. Such an approach, however, requires us to continue to base our ratemaking decisions on a book basis and to calculate the capital savings based on what we believe to be the appropriate cost of capital and capital structure for the regulated electric utility. We agree with the Company that in calculating the capital savings associated with the asset sale gain account, it is necessary to factor in the impact of deferred taxes. Our ratemaking treatment for the regulatory gain account is, thus, identical to the ratemaking treatment which we have afforded to the Company in the past when we approved the creation of a regulatory asset and, in fact, is the same treatment recommended by the Company for the account as of the date of restructuring.

Since we have, as part of this Order, established what we believe is the proper cost of capital and capital structure for the Company both as of today and at the start of restructuring, we will base the carrying costs to be applied to the Asset

Sale Gain Account on the overall weighted pre-tax cost of capital of 12.22%. *See Part I, Section VI, D.2, infra.*

IV. NON-DIVESTED GENERATION ASSETS

A. Hydro-Quebec

CMP is a participant in the interconnection arrangement between New England and Hydro-Quebec (HQ). CMP has an entitlement to capacity on the HQ tie-line through the year 2019. In exchange, CMP is obligated to make support payments to the tie-line owners. CMP estimates its support payments to be $6,613,500 in the rate year, and for the entire contract period to be $42,868,000 at year-end 1999 on a present value basis. Purchases and sales with HQ are pursuant to several agreements, the most significant of which is the Firm Energy Contract (FEC). Under the FEC, participants can purchase up to 7 terawatt hours of energy annually from HQ at prices equal to 95% of the average cost of fossil generation in New England. CMP shares in savings from the contract that accrue from displacing the more expensive fossil generation with the FEC energy. CMP's share of energy under the FEC has historically been about 490 GWh/yr and has been priced from between $17 to $22/MWh. The FEC terminates in August, 2000. There appears to be an energy "backlog," however, so that CMP will continue to receive energy after that. CMP also has historically received a capacity benefit of approximately 100 MW from its participation.

1. Positions Before the Commission

In the stranded cost estimates presented in this case, CMP included the HQ support payments without any offsetting value, and assumed that FEC's costs and value offset one another. CMP, however, does not assert that its entitlement in the HQ tie line is valueless, rather that at this time the value is too uncertain to quantify. CMP states in its Brief that it proposes to sell all of its rights and obligations associated with the interconnection beginning March 1, 2000. CMP also notes that treatment of the tie-line by FERC remains uncertain. CMP proposes that its HQ-related stranded costs be set in the 1999 update in Phase II.

RWS asserts that HQ tie-line costs are transmission-related and, thus, should not be counted as a stranded cost. RWS argues in the alternative that HQ-related costs would be offset by the value of the associated resources.

2. Analysis and Conclusion

The primary purpose of the HQ tie-line and CMP's participation therein is to access capacity and energy from Quebec. The tie-line, thus, is a generation-related asset for which the Act requires divestiture. 35-A M.R.S.A.

§ 3204(1). As a non-exempted power contract, the FEC must also be divested. CMP sought bids for the HQ resources in its recent divestiture process but did not accept any of the bids. CMP must try again to divest these items by March 1, 2000 or request an extension from the Commission pursuant to 35-A M.R.S.A. § 3204(3). If CMP receives such an extension, it would be required to sell its entitlements through periodic auction processes, similar to how it will sell its QF entitlements. Finally, we agree with CMP that HQ stranded costs should be set in Phase II.

B. Nuclear Assets/Obligations

Since all nuclear costs are generation-related, they are stranded by the deregulation of generation service, or are already "stranded" by the shutdown of the power plants.

1. Decommissioning

CMP includes in its T&D revenue requirement the decommissioning and O&M expenses for the shut down nuclear plants and the decommissioning trust fund payments for its two operating nuclear plants.[30] CMP includes decommissioning costs as an adjustment to the T&D revenue requirement rather than to the stranded cost calculation because the Restructuring Act specifically mentions decommissioning as recoverable in T&D rates.

We agree with CMP that the Legislature explicitly authorized decommissioning costs in T&D **rates**. 35-A M.R.S.A. § 3209(4). The Legislature also authorized stranded costs in T&D rates. The Legislature did not categorize decommissioning costs as T&D **costs**. In fact, decommissioning costs are generation-related and not on-going T&D costs. Indeed, a contrary legislative categorization would be inconsistent with the general restructuring scheme of separating generation from T&D.

Prudent and reasonable decommissioning costs are legitimate costs of operating (or having operated) a nuclear power plant. As such, the prudent and reasonable expenses should be recovered from T&D ratepayers as stranded costs. The bulk of the decommissioning expenses are for plants that are regulated by FERC, and consequently FERC will decide the prudence and reasonableness of those decommissioning expenses.

[30]The Maine Yankee, Connecticut Yankee and Yankee Atomic (Yankee Rowe) plants are shutdown. Millstone Unit 3 and Vermont Yankee still operate. CMP owns 38% of Maine Yankee, 6% of Connecticut Yankee, 9.5% of Yankee Atomic, 2.5% of Millstone 3 and 4% of Vermont Yankee.

2. Operating Plants

CMP owns an interest in two operating nuclear power plants, Millstone Unit 3 and Vermont Yankee. Although CMP included its interests in each plant in its auction process, CMP did not sell either nuclear power plant interest nor the entitlement to the output of either plant. The Restructuring Act does not require divestiture of the nuclear assets, and it appears unlikely that either asset will be divested before March 1, 2000. Since the provisions of section 3204(4) will apply, must sell its entitlement to the output of the nuclear plants, similar to its sale of its QF entitlements.

a. Millstone 3

We have already discussed CMP's proposal to write off its Millstone 3 book investment against available asset sale value. To determine total stranded costs associated with Millstone 3, we must subtract the operating costs, including decommissioning costs and return of, and on, the investment, from the revenue received for the output of the plant. An update will be necessary to determine both the revenue received for the plant output and the reasonable operating costs. Millstone 3 was out of service for over two years, and this outage was found imprudent by the Connecticut Department of Public Utility Control (DPUC). The plant has been back on line only since July, 1998. We will need the 1998-99 actual operating expenses to accurately forecast the rate year O&M costs and capacity factor. Furthermore, CMP states that the Connecticut DPUC will set a new decommissioning funding requirement for Northeast Utilities (NU), the lead owner. We have traditionally relied on the Connecticut Commission's decommissioning investigation rather than conduct our own.

Additional information may be relevant to determining the reasonable Millstone operating and capital costs. The minority owners, including CMP, brought an arbitration proceeding and a lawsuit in Massachusetts against the lead owner, Northeast Utilities, similar to an imprudence investigation. Depending on the results of the arbitration, NU may be responsible for any increased O&M expenses in the restarted power plant or any capital additions that were required during the recent outage. Other than capital additions during the recent outage mentioned above, there is no controversy about the prudent level of rate base investment by CMP in Millstone 3.

To summarize, we will set the stranded costs associated with Millstone 3 by estimating the rate year O&M, rate base and return, and output of the plant. Next we will subtract the compensation received by CMP for the sale of the output of the plant. We will calculate this adjustment to stranded costs in Phase II.

b. Vermont Yankee

We will calculate the stranded costs associated with Vermont Yankee in a manner similar to Millstone 3's. Since Vermont Yankee has not been in an extended outage, the estimation of the O&M, rate base and output of the plant should not be controversial. These items will be updated during 1999 in Phase II. For decommissioning, CMP used Vermont Yankee's year 2000 budget. T&D rates should be based upon the actual decommissioning rates allowed by FERC.

3. Shutdown Nuclear Plants

a. Maine Yankee

CMP's investment in Maine Yankee represents its largest stranded cost associated with nuclear investments. Significant issues concerning the prudence of the operation and shutdown of the plant have been raised in two cases pending at FERC; a Maine Yankee rate case and a complaint case brought by the Public Advocate. FERC will also decide the decommissioning rates for Maine Yankee.

On December 31, 1998 the Commission entered into an offer of settlement in the FERC cases. The settlement will resolve prudence and decommissioning issues. For calculation purposes, we have assumed the settlement is approved by FERC. Under the settlement, some prudence adjustments cannot be calculated until after 2004 and therefore await future retail stranded cost updates to be implemented. We use, and flow through to retail ratepayers, the 6.5% return on equity. We estimate decommissioning expenses at the amounts contained within the settlement. We also order CMP to defer any refunds received from the decommissioning trust fund or spent fuel trust fund payments. We expect that value to be returned to ratepayers during some future stranded cost update proceeding.

CMP owns 38% of the Maine Yankee corporation, but it receives and pays only 37.456% of the output and expense obligations because of the terms of Purchase Contracts between owners such as CMP and secondary purchasers. Secondary purchasers in Maine (EMEC and Houlton Water) receive .544% of CMP's output from and cost responsibility for the plant. CMP has estimated its share of decommissioning and O&M costs for Maine Yankee at the 38% ownership share rather than the 37.456% power entitlement share. CMP reasons that the secondary purchasers have stopped payments since the shutdown and by the Purchase Power Agreement between Maine Yankee and the other owners, CMP is obligated to pay its full 38% ownership proportion.

However, on January 29, 1999 the secondary purchasers entered into a Settlement Agreement with Maine Yankee in the FERC case. By the terms of the agreement, secondary purchasers will pay various Maine Yankee owners, including CMP, amounts described in the agreement to settle all claims by both owners and secondary purchases. This settlement was reached after the close of the record, and CMP has not had the opportunity to adjust its stranded cost request to reflect the settlement. It certainly appears that CMP's original requested adjustment is no longer accurate. The proper stranded cost rate making treatment of the settlement agreement with the secondary purchases should be addressed by CMP in its Phase II filing.

b. Connecticut Yankee

FERC also must decide the prudence of the shutdown and operation of the Connecticut Yankee plant, as well as the recoverability of the plant investment from wholesale ratepayers like CMP. The FERC ALJ in Connecticut Yankee Atomic Power Company, 84 FERC ¶ 63,009 (FERC docket no. ER97-913-000, August 31, 1998), recommended that FERC reject Connecticut Yankee's requested increase in decommissioning rates and permit recovery of the undepreciated investment from wholesale customers but allow no return on investment to compensate for imprudent operation. We hope the FERC will decide the case by the end of the Phase II proceeding.

c. Yankee Rowe

The FERC has already decided the shutdown prudence issue for Yankee Rowe. Yankee Rowe is almost completely decommissioned. Most of the remaining decommissioning expense concerns the storage of spent fuel. Yankee Rowe has a claim against the Department of Energy for these expenses as breach of contract damages. CMP may recover some of these expenses in the future, and any recovery should be deferred and flowed through to ratepayers whenever stranded costs rates are adjusted.

4. Mitigation

CMP attempted to mitigate stranded costs associated with its nuclear investments by including Millstone 3 and Vermont Yankee in the Company's auction process. CMP rejected all bids for the nuclear investments and the power output from those plants. The Commission found that CMP's decisions to reject all nuclear-related bids were reasonable in the sale of assets case. In addition, as to Millstone 3, CMP has sued and sought arbitration to recover for the mismanagement of the power plant by the lead owner, Northeast Utilities. The outcome of that dispute may be used to mitigate the amount of stranded costs associated with Millstone 3. CMP should report on the results of the arbitration and Connecticut DPUC's ratemaking treatment for Millstone 3 in Phase II.

CMP remains under an obligation to mitigate its stranded costs associated with the shutdown nuclear plants by assuring that the decommissioning expenses and spent fuel storage costs are incurred reasonably.[31] For the most part,

[31] Maine Yankee's process of selecting a Decommissioning Operations

however, we expect future mitigation efforts at Maine Yankee and Connecticut Yankee to be within the ratemaking jurisdiction of FERC. We expect CMP and Maine Yankee to keep us informed of these efforts.

V. QUALIFYING FACILITY CONTRACTS

A. Summary of Issue

CMP has 62 qualifying facilities (QF) contracts with terms that extend past March 1, 2000.[32] The longest remaining contract extends into the year 2016. These contracts are projected to provide approximately 465 MW of capacity and over 3 million MWh of energy in the year 2000. The capacity and energy provided by CMP's QF contracts will remain at approximately these levels through 2005, declining steadily thereafter.

The Bench Analysis estimated that CMP's QF contract payments in the rate year would be approximately $285 million. Although these payments will be offset by the value CMP receives for the QF capacity and energy, these contracts clearly will remain a major component of CMP's stranded cost revenue requirement for the next several years.

In this case, the Commission must establish the level of QF-related stranded costs to be recovered in rates effective March 1, 2000. This involves: (1) determining the time period over which to measure stranded costs; (2) estimating total QF contractual payments during that period; (3) establishing the market value of the associated capacity and energy; (4) considering future mitigation e.g., through contract buydowns; and (5) evaluating the adequacy of CMP's mitigation efforts. Although parties and the Bench Analysis have presented QF-related stranded cost estimates, these amounts must be updated in late 1999 or early 2000 when contractual payments can be more accurately determined and the results of the bid process for QF capacity and energy entitlements are known.[33]

Contractor is as an example of reasonable cost mitigation.

[32]This includes contracts with non-QF entities entered solely for the purpose of restructuring a QF contract. Pursuant to the Restructuring Act, these are treated like contracts with QFs.

[33]35-A M.R.S.A. § 3204(4) requires CMP to sell its entitlements to this capacity and energy according to Commission rules. The Commission's provisionally adopted Chapter 307 contemplates that CMP would issue a request for bids in August 1999 and that bids would be filed on October 1, 1999.

B. Relevant Time Period

1. Positions Before the Commission

CMP proposes to define QF-related stranded costs as the difference between future costs of the contracts and the market value of the associated capacity and energy. CMP would estimate its payments under the contracts during the rate effective year to define contract costs and would use the actual prices received when it sells its entitlements to the capacity and energy pursuant to 35-A M.R.S.A. § 3204(4) as the market value.

RWS argues that CMP's method would incorrectly measure stranded costs and would violate the stranded cost section of the Restructuring Act. 35-A M.R.S.A. § 3208. According to RWS, rates must reflect stranded costs measured over the life of the contracts.

2. Analysis and Conclusion

For the reasons discussed more fully in Section III(B)(2), we do not agree with RWS's position. Estimating the costs and value of CMP's QF contracts over their remaining terms, the longest of which extends into the year 2016, is neither required by the Act nor would it be a methodological improvement to the basic approach proposed by CMP. Such estimates would rely on long-term projections of facility operation and contractual prices, as well as market values for capacity and energy, all of which would be fraught with uncertainty.

RWS's concern may in part be motivated by its assumption that under CMP's proposed method, ratepayers would not receive any benefits from future years in which stranded costs are negative, i.e., when market values exceed costs. This assumption is erroneous. There is no dispute that QF-related stranded costs are the difference between contract costs and value. This amount can be positive or negative. If in future periods the amount is negative, QF-related stranded costs will result in a rate credit to CMP's customers.

However, RWS's argument does point out a deficiency in CMP's approach. Under CMP's approach, rates would reflect QF stranded costs over the March 2000 - February 2001 period. Unless stranded cost charges are reset, CMP would overrecover QF stranded costs in subsequent periods. This is because, as noted by RWS, stranded costs tend to be front-end loaded. In other words, CMP's total QF payments decrease and the value of the associated capacity and energy generally increase with time. For example, using CMP's estimates, QF-related stranded costs would be $173 million in the March, 2000 - February, 2001 rate year, and $147 million in the following year.

Because the Act requires a review of stranded cost at least once every three years and allows the Commission to adjust stranded cost charges if the review indicates substantial inaccuracies in then-current charges, it also seems logical to coordinate the rate setting in this proceeding with such reviews and potential rate adjustments. Because subsequent sales could yield substantially different values, the sale period for the QF entitlement will likely define when our periodic reviews occur. Thus, the cost pattern of QF contracts, the likelihood that QF entitlements will be sold for periods of two or three years[34] and the review and rate adjustment provisions of the Act suggest that an equitable and logical approach is to calculate charges based on the time period for which QF entitlements are sold. In the present case, if CMP sells its entitlements for the 2-year period, March 1, 2000 through February 2002, rates would reflect a present value of stranded costs over that period. Similarly, if it sells its entitlements over a 3-year period, rates would reflect a present value over March 1, 2000 through February 2003. This could be accomplished by including in revenue requirements a levelized stranded cost charge over the period of the sale.

In its exceptions, the Company argues that the levelized approach discussed above would result in the Company's under-collecting revenues in the initial year of the recovery period, which would adversely impact its financial results. We believe that this financial reporting issue can be adequately addressed through the entry of appropriate accounting orders. We will allow the Company to present evidence in Phase II of this proceeding to show that the financial reporting issue cannot be adequately addressed through regulatory accounting procedures.

C. QF Payments

CMP proposes to estimate future payments to QFs as the product of the estimated purchase quantities from each contract and the estimated contractual purchase price. CMP would use the most recent 5-year historic period to project the purchase quantities from each hydro, wind and photovoltaic facility. If historical data were not available, it would base its projection on other available information such as the output of a similar facility. For each thermal QF, CMP would use the average generation purchased during the most recent three years of mature operation for the plant.

Purchase prices are fixed by contract for facilities representing about 50% of CMP's QF payment dollars. For contracts that do not contain fixed prices, prices are function of one of the following: inflation; retail industrial rates; market prices; or Commission-set avoided costs. CMP also has several customer net energy billing arrangements (CNEBAs) with facilities of less than 100 kW.

[34]The Commission's provisionally adopted Chapter 307 contains a 2-year sale period.

1. Inflation

CMP has six contracts in which purchase prices change as a function of the Gross National Product Implicit Price Deflator (GNP-IPD). These are with: Champion Paper; Gorbell/Thermo-Electric; Brassua; Merimil; Barker Upper; and CL Power Sales 8. CMP estimates total payments under these contracts to be $50.312 million in the rate year but proposes that this amount actually be set during the update phase of this proceeding in 1999, at which time prices could be more accurately estimated using current, publicly available sources of GNP-IPD. We agree with CMP's proposed approach to update these contract costs in Phase II.

2. Retail Industrial Rates

CMP will have two contracts after March 1, 2000 in which prices are a function of retail electricity rates. These contracts are with United American Energy (UAE), a 17.15-MW hydro facility, and S.D. Warren - Somerset (S.D. Warren), an 87-MW simultaneous buy-sell arrangement involving the S.D. Warren mill and its cogeneration facility. The prices in both contracts are set by reference to industrial electricity rates. The UAE prices are a function of CMP's LGS-ST rate. The S.D. Warren prices are equal to CMP's LGS-T rate.[35] CMP estimates rate-year payments of $7.6 million to UAE and $41.9 million to S.D. Warren by assuming that the relevant electricity prices that drive these contracts remain constant at today's levels.

It remains unclear how these contracts will operate after March 1, 2000. Because the price-terms rely upon CMP's bundled rates, the Act requires the Commission, at the request of any QF, to establish a proxy rate that reflects combined T&D and generation prices to serve as the basis for future payments under its contract. (P.L. 1997, ch. 316 Unallocated, Sec. 6). To date, neither UAE or S.D. Warren has made such a request.

CMP proposes that the costs of these contracts be set as part of the update proceeding by which time the pricing under these contracts may be clearer. We agree that the cost of these contracts should be reviewed at that time. However, if the pricing under these contracts has not been resolved through negotiation or by the Commission at the request of UAE and/or S.D. Warren, CMP should submit a proposal for defining the contract prices and reflecting the costs of these contracts in stranded cost charges.

3. Market Price

CMP has two contracts in which prices are indexed to market electricity rates: Greenville Steam and Worumbo. According to CMP, both contracts require prices to be set based on a month-by-month backward-looking calculation of

[35]This is the case as of 1998.

New England market prices. Again, CMP proposes to update the contract costs in 1999, and we concur.

4. Long-Term Avoided Costs

CMP has four contracts which depend upon long-term avoided costs that were not set when the contracts were executed: RWS, Aziscohos, Benton Falls, and LaValley Lumber. These contracts define prices by reference to certain Commission-set avoided costs, but do not contain actual numbers. CMP recommends that the prices it receives when it sells its entitlements to the capacity and energy from the contracts define avoided cost for this purpose. CMP notes that both RWS and Benton Falls have previously taken the position that the Commission has already set the avoided costs applicable to their contracts, and that the entitlement sale prices are not applicable. RWS and CMP are currently litigating this aspect of their contract.

RWS argues in this proceeding that, during Period Two of its contract (2001-2008), it is entitled to prices that, at minimum, are equal to 90.686% of the Decrement 87-A avoided costs established by the Commission in Docket No. 87-261. RWS indicates that this would result in contract base rates ranging from $0.0805/kWh in 2001 to $0.1003/kWh in 2008. RWS asserts that Decrement 87-A provides a reasonable surrogate for the avoided costs contemplated in its contract.

We will estimate the costs of these contracts in the update phase based on our interpretation of each contract's intent, the policies embodied in the Restructuring Act and avoided-cost estimates.

D. Future Mitigation

1. Summary of Issue

In setting stranded cost charges, the Commission must consider how to reflect savings from future QF contract restructurings. There are three basic approaches: (1) estimate savings and reflect them in March 1, 2000 rates; (2) adopt an incentive mechanism for future restructurings that would also provide a sharing of savings between shareholders and ratepayers; or (3) defer savings for future rate treatment.

CMP witnesses presented an incentive mechanism approach for future QF mitigation. In a Procedural Order dated January 29, 1998, the Hearing Examiner concluded that whether, and how, incentive regulatory mechanisms should be continued after the current ARP expires were beyond the scope of this proceeding. Although we anticipate that an incentive regulatory mechanism for the T&D utility will be considered at some point, it appears unlikely that one would be in place by March 1, 2000. Therefore, the remaining options are either to reflect in rates an estimate of future savings or to defer all future savings.

2. Positions Before the Commission

CMP offered no alternative after the Examiner eliminated consideration of its proposed incentive mechanism from the case. CMP's position is that March 1, 2000 rates should reflect no savings from contract restructurings that occur after rates are finally set in this case. CMP argues that to reflect in rates any estimate of future savings would be improper and unfair because contract restructuring opportunities are limited and savings cannot be predicted accurately.

3. Analysis and Conclusion

We acknowledge the logic of CMP's point that opportunities for savings decline over time as the universe of remaining candidate contracts becomes smaller. We also do not disagree that savings cannot be predicted precisely. However, CMP's proposal that we implicitly assume that there will be no savings is not a solution.[36] CMP's proposal simply would reflect in rates an estimate of zero savings during the period, although it has presented no evidence that zero is the most reasonable estimate of the savings. For CMP's approach to meet the standard set forth in 35-A M.R.S.A. § 3208 that the Commission consider a utility's mitigation efforts when determining stranded costs, there must be such evidence. Therefore, we reject CMP's approach.

The options, then, are to reasonably estimate the savings or to defer the savings.[37] In its exceptions to the Examiner's Report, CMP indicated that the deferral mechanism was an acceptable means of capturing future QF savings for ratepayers. Although either of the two approaches is acceptable, for the reasons set forth below, we prefer the latter.

By deferring the savings associated with future QF contracts, the Commission can ensure that the actual savings will be passed through to ratepayers and that the Company will not recognize a windfall if it successfully restructures a contract. To ensure that CMP aggressively pursues all appropriate QF restructuring opportunities, we will allow the Company to retain 10% of the net savings resulting from QF buyouts or restructurings occurring after March 1, 2000.

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[36]There are many components we must establish in setting CMP's revenue requirement and rates that cannot be predicted precisely, e.g., sales. However, this does not mean we must assume they will equal zero.

[37]An incentive mechanism could replace either of these at some future point.

E. Past Mitigation

1. Summary of Issue

The standards set forth in the Act also require the Commission to consider the adequacy of CMP's past QF restructuring efforts. Specifically, the Act requires that

> An electric utility shall pursue all reasonable means to reduce its potential stranded costs . . . including the exploration of all reasonable and lawful opportunities to reduce the cost to ratepayers of contracts with qualifying facilities. The Commission shall consider a utility's efforts to satisfy this requirement when determining the amount of a utility's stranded costs.

35-A M.R.S.A. § 3208(4).

2. Positions Before the Commission

CMP argues that it has met its obligations under section 3208(4). CMP describes its three strategies: (1) strict contract enforcement, (2) pursuit of legislative changes, and (3) contract restructurings. CMP notes that its most successful strategy, contract restructurings, has resulted in NPV savings of almost $500 million, which it characterizes as highly successful.

The OPA expressed a concern about the corporate resources and apparent priority CMP devotes to stranded cost mitigation. The OPA argues that mitigation should have a higher priority than is suggested by CMP's organizational chart and the spending authority of the responsible unit, Purchased Power Administration.

3. Analysis and Conclusion

Notwithstanding the OPA's expressed concerns, no party has provided evidence in this case that CMP's QF mitigation efforts fall short of the standard set in 35-A M.R.S.A. § 3208(4). Given that many of CMP's largest QFs are parties to this proceeding, we assume they would have brought such evidence to light if CMP had been lax in pursuing advantageous contract restructuring opportunities. They did not. Moreover, to a large degree the Stipulations we accepted in Docket Nos. 92-102 and 94-103 disposed of this issue for CMP’s actions prior to March, 1994. *Order Approving Stipulations,* Docket Nos. 94-103, 92-102 (July 21, 1994). Finally, our own review of CMP's QF restructuring achievements and our familiarity with CMP's efforts in numerous individual contract restructuring cases indicate CMP's efforts and results are reasonable. We find CMP to have met the section 3208(4) standard with respect to QF mitigation to date.

As for the concerns raised by the OPA, we agree that CMP should continue to aggressively pursue stranded cost mitigation through QF contract restructurings, as well as the sale of entitlements; it must do so in order to continue to meet the section 3208(4) standard. The record indicates that contract restructuring opportunities still remain, and we expect that CMP to pursue them vigorously. We will carefully re-evaluate CMP's mitigation efforts each time we re-examine stranded costs.